# AN ECONOMIC ANALYSIS OF THE KILAUEA GEOTHERMAL DEVELOPMENT AND INTER-ISLAND CABLE PROJECT

By

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# HIGHLIGHTS AND CONCLUSIONS

A study by NEA completed in April 1987 shows that a large scale (500 MW) geothermal development on the big island of Hawaii and the inter-island power transmission cable is economically infeasible. This updated report, utilizing additional information available since 1987, reaches the same conclusion:

- The state estimate of $1.7 billion for development cost of the geothermal project is low and extremely optimistic. More realistic development costs are shown to be in the range of $3.4 to $4.3 billion and could go as high as $4.6 billion.

- Compared to alternative sources of power generation, geothermal can be 1.7 to 2.4 times as costly as oil, and 1.2 to 1.7 times as costly as a solar/oil generating system.

- Yearly operation and maintenance costs for the large scale geothermal project are estimated to be 44.7 million, 72% greater than a solar/oil generating system.

- Over a 40-year period ratepayers could pay, on average, between 1.3 (17.2%) and 2.4 cents (33%) per kWh per year more for electricity produced by geothermal than they are currently paying (even with oil prices stabilizing at $45 per barrel in 2010).

- A comparable solar/oil thermal energy development project is technologically feasible, could be island specific, and would cost 20% to 40% less than the proposed geothermal development.

- Conservation is the cheapest alternative of all, can significantly reduce demand, and provides the greatest return to ratepayers.

There are better options than geothermal. Before the State commits the people of Hawaii to future indebtedness and unnecessary electricity rate increases, more specific study should be conducted on the economic feasibility, timing, and magnitude of the geothermal project. The California experience at The Geyers points up the fact that it can be a very risky and disappointing proposition. The state should demand that proponents and developers provide specific answers to geothermals troubling questions before they make an irreversible commitment to it.

The state should also more carefully assess the potential risks and hazards of volcanic disturbances, the degree of environmental damage that could occur, the future demand for electricity, and the potential of supplying electricity from alternative energy sources, conservation and small scale power units. As we stated in the April 1987 study, to move ahead with rapid large scale geothermal development on Hawaii without thoroughly studying these aspects of its development is ill-advised and economically unsound.

# INTRODUCTION

In early 1989 the Pele Defense Fund requested that Northwest Economic Associates (NEA) update their 1987 economic analysis of the proposed Hawaii Geothermal Development And Inter-island Cable Transmission System Project. This report, the result of that request, once again compares the cost of building and operating 500 MW of geothermal power plants and a cable transmission system with the cost of building and operating 500 MW of oil-fired power plant generating capacity. This update also compares the geothermal project with a solar/oil hybrid generating system of the same size. The impact of energy conservation is also considered in terms of its potential as an energy resource and in its contribution to an energy development program for the state of Hawaii.

This report develops low and high cost estimates for the project. In a project laced with as much uncertainty as this, a single cost figure is of little value. A range of values which attempts to account for some of the uncertainty seems a more logical approach to cost estimation.

Our cost estimates include costs which should have been considered in the February 1988 Decision Analysts Hawaii, Inc. report for the State, but were not. The most obvious being a standard project cost contingency. Other costs not considered in the State report but included in this report are:

1) additional cost of the undersea cable to allow for slope changes on the sea floor,

2) cost of constructing the cable laying vessel which does not yet exist,

3) cost of helper vessels to assist in the cable laying, and

4) adequate insurance or plant replacement costs.

A cost that neither the State report nor this report includes, but one that may be very important, is the cost of designing or protecting the plants to deal with geologic hazards. The added cost of strengthening plants, designing them for quick disassembly, or constructing protective barriers around them will be considerable.

This report considers project costs as objectively as possible considering the great deal of uncertainty and high level of risk involved in the project.

All costs are shown in 1990 dollars.

Appenix C contains two criticisms of the February 1988 Decision Analysts Hawaii, Inc. report on the proposed geothermal project.

# THE GEOTHERMAL PROJECT AS CURRENTLY ENVISIONED

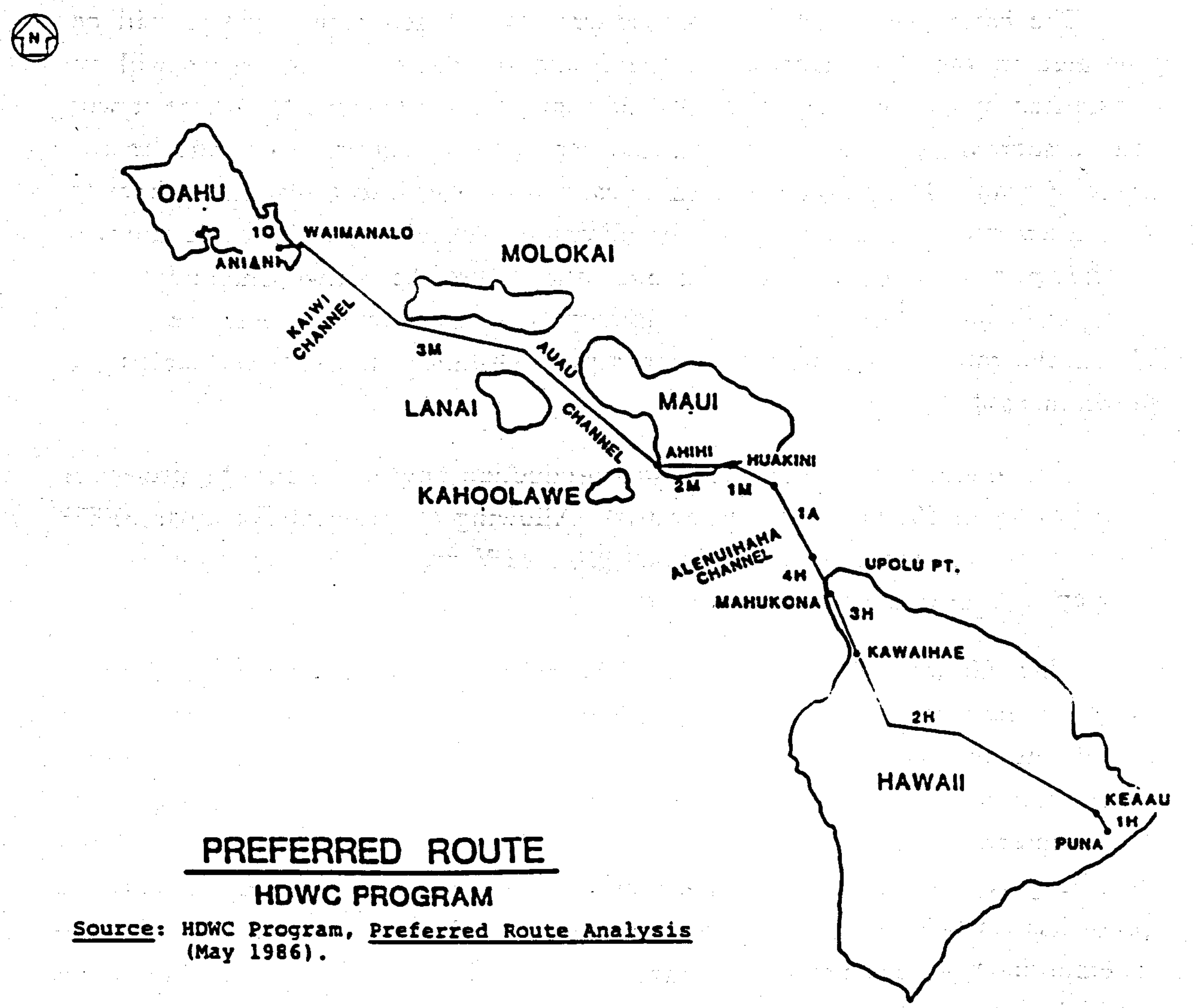
The basic project scenario is that 500 MW of geothermal power will be generated in the Puna District on the Island of Hawaii. The power will be transmitted by overhead cables across the island to its northern tip where it will enter a submarine cable for transmission across the Alenuihaha Channel to the Island of Maui. The power will then be carried by overhead transmission lines to the southwest corner of Maui where it will enter a second submarine cable and will be transmitted along the Auau Channel and across the Kaiwi Channel to the Island of Oahu for distribution to customers. Figure 1 shows the described route. This is the route that is used in our analysis. Distances and channel depths are shown in Table 1.

The amount of geothermal power production envisioned for the project is on the order of 500 net MW (megawatts). Allowing for transmission losses (10%) and adequate power reserve, (20%) 600 gross MW must be proven to exist and developed to meet project requirements.

The 500 net MW of power would be provided by a number of geothermal power plants located in the area of the East Rift Zone of Kilauea volcano (Figure 2). The number of plants that will be required to produce the 500 net MW would either be ten 55 MW plants, twenty 27.5 MW plants, or some combination of the two proposed sizes. The distribution and location of the plants and their wellfields will be governed by the distribution and location of the resource, but since no proof has yet been established that the necessary 600 gross MW actually exists, no attempt has been made to show a likely plant distribution pattern. In conjunction with the power plants and wellfields are the transmission cables (overhead and underwater) and their associated facilities. A general list of the system components is found in Table 2.

Figure 1

PREFERRED ROUTE
HDWC PROGRAM




Source: HDWC Program, Preferred Route Analysis (May, 1986).

NEA
Source: *Alternative Approaches to the Legal, Institutional, and Financial Aspects of Developing an Inter-island Electrical Transmission Cable System,* State of Hawaii, Department of Planning and Economic Development, April, 1986.

## Table 1

### DISTANCE AND DEPTH CHARACTERISTICS OF PREFERRED ROUTE, April, 1986

### Hawaii to Maui to Oahu

| From | To | Segment | OH/SUB | Length KM | Length MI |
|---|---|---|---|---|---|
| Puna | Keaau | 1H | OH | 23 | 14 |
| Keaau | Kawaihae | 2H | OH | 129 | 80 |
| Kawaihae | Mahukona | 3H | OH | 23 | 14 |
| Mahukona | Alenuihaha | 4H | SUB | 32 | 20 |
| Alenuihaha | Alenuihaha | 1A | SUB | 19 | 12 |
| Alenuihaha | Huakini Bay | 1M | SUB | 16 | 10 |
| Huakini Bay | Ahihi Bay | 2M | OH | 32 | 20 |
| Ahihi Bay | Waimanalo | 3M | SUB | 154 | 96 |
| Waimanalo | Aniani | 1O | OH | 5 | 3 |
| | | Total Overhead | | 212 | 131 |
| | | Total Submarine | | 221 | 138 |

Percentage Submarine = 51%
Longest Submarine Run = 154 km

### Approximate Distance Within Depth Ranges For Submarine Portions (KM)

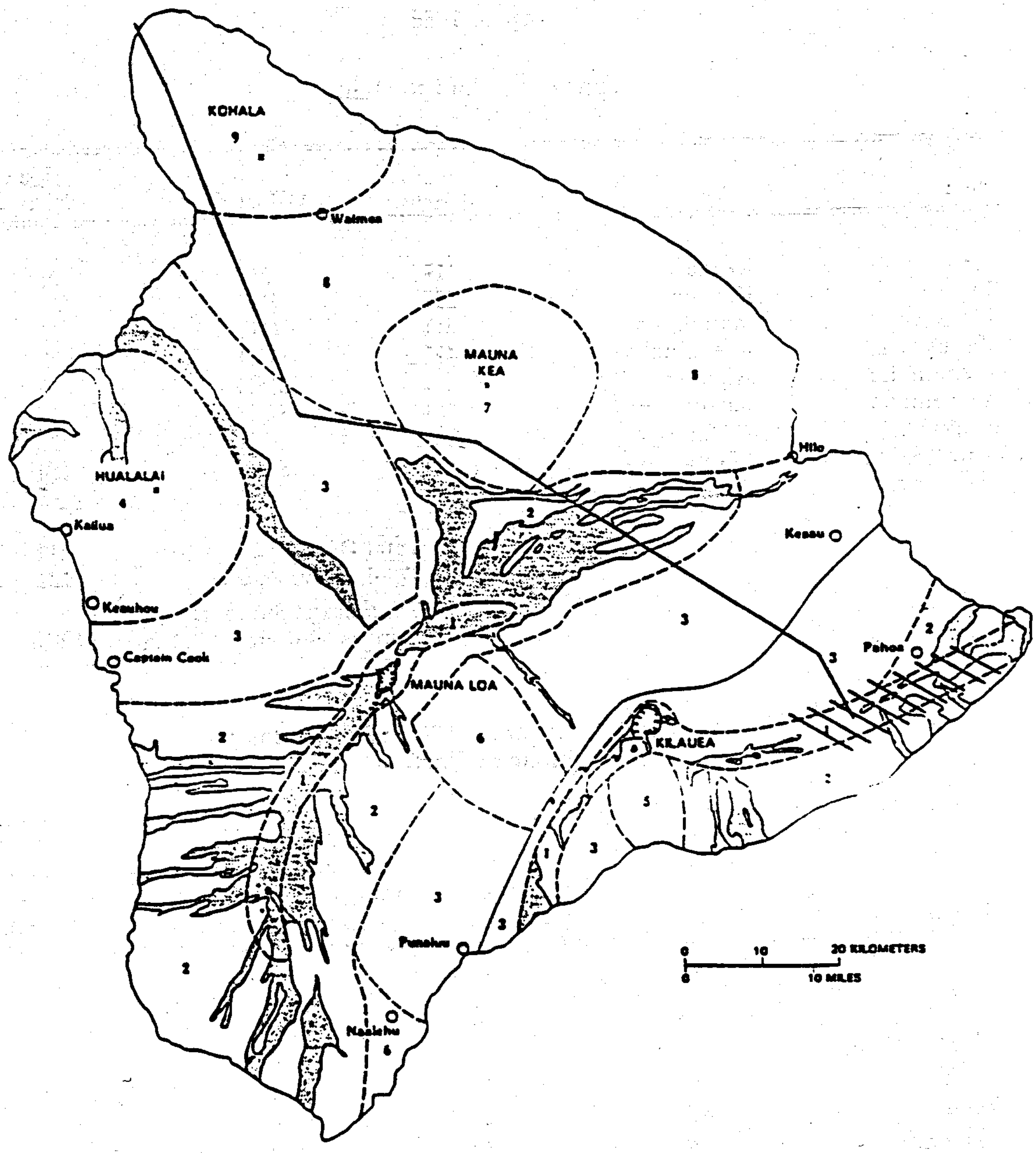
| Segment | Depth 0-1800 / 0-547 / 0-300 | 1800-3600 / 547-1094 / 300-600 | 3600-5400 / 1094-1641 / 600-900 | 5400-7200 / 1641-2188 / 900-1200 | Feet / Meters / Fathoms |
|---|---|---|---|---|---|
| 4H | 27 | 5 | – | – | |
| 1A | – | 10 | 1 | 8 | |
| 1M | 7 | 2 | 7 | – | |
| 3M | 144 | 10 | – | – | |
| Total | 178 | 27 | 8 | 8 | |
| Percent | 80.5 | 12.2 | 3.62 | 3.62 | |

Source: HDWC Program. Preferred Route Analysis (May, 1986).

NEA Source: *Alternative Approaches to the Legal, Institutional, and Financial Aspects of Developing an Inter-island Electrical Transmission Cable System*, State of Hawaii, Department of Planning and Economic Development, April, 1986.

## Figure 2

## AREA OF PROPOSED GEOTHERMAL FACILITIES




\\\\ Geothermal Plant Location

— Transmission on Line Route

Source: <u>Volcanism In Hawaii</u>, U.S. Geological Survey Professional Paper 1350.

## Table 2

## CABLE SYSTEM FACILITIES

A cable system's facilities would consist, in the general order of sequence from the energy generation source, of the following components:

- The interconnection facilities (alternating current) to transmit the renewable alternate energy-generated electric energy from the power plants to the cable system's converter station on the Island of Hawaii;
- The land-based converter station on the Island of Hawaii to convert alternating current (ac) to direct current (dc) for cable transmission;
- The overhead transmission line traversing the Island of Hawaii to the land-based cable termination facility, including an oil pressurization station;
- The submarine cable system to Maui;
- The land-based oil repressurization station on Maui;
- The submarine cable system to Oahu;
- A land-based cable termination facility on Oahu;
- The overhead hvdc transmission line from the cable termination facility to the converter station on Oahu;
- The converter station to convert dc to ac for interconnection to HECO's grid system; and
- The interconnection facilities to transmit electric energy from the cable to HECO's grid system.

NEA
Source: *Alternative Approaches to the Legal, Institutional, and Financial Aspects of Developing an Inter-island Electrical Transmission Cable System*. State of Hawaii, Department of Planning and Economic Development, April, 1986.

# THE COST OF THE GEOTHERMAL PROJECT AS CURRENTLY ENVISIONED

In February, 1988, Decision Analysts Hawaii, Inc. (DAHI) submitted a report on the economic feasibility of the 500 MW geothermal project. It estimated the development cost at 1.675 billion (1986) dollars. Actual bids on the project have not been made public but speculation in the news media places them at above the $3 billion mark.[1] If these estimates prove accurate, they show the DAHI cost estimate to be more than a billion dollars low.

Table 3
PROJECT DEVELOPMENT COST COMPARISON

| 25 Net MW Plants Capital Cost Comparison (M$) | Plant/Wellfield Surface Facilities | Wells | Cables | Total Cost |
|---|---|---|---|---|
| **Without Contingency:** | | | | |
| DAHI 1986$ | 662.2 | 600.0 | 413.3 | 1675.5 |
| DAHI 1990$[2/] | 700.9 | 600.0 | 444.4 | 1745.3 |
| NEA 1990$ (low estimate) | 984.6 | 675.0 | 561.4 | 2221.0 |
| NEA 1990$ (high estimate) | 1104.6 | 900.0 | 561.4 | 2566.0 |
| **With 20% Contingency:** | | | | |
| DAHI 1990$ | 841.1 | 720.0 | 533.2 | 2094.3 |
| NEA 1990$ (low estimate) | 1345.9 | 810.0 | 673.5 | 2829.4 |
| NEA 1990$ (high estimate) | 1507.9 | 1080.0 | 673.5 | 3261.4 |
| **With 20% Contingency & Replacement Wells:** | | | | |
| DAHI 1990$ | 841.1 | 1440.0 | 533.2 | 2814.3 |
| NEA 1990$ (low estimate) | 1345.9 | 1620.0 | 673.5 | 3639.4 |
| NEA 1990$ (high estimate) | 1507.9 | 2160.0 | 673.5 | 4341.4 |

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1/ Star-Bulletin, Special Report: Geothermal–A Heated Issue, by Susan Manuel, January 2, 1990.

2/ The 1986 DAHI cost figures are brought up to 1990 levels using inflation rates calculated from indexes found in the *Statistical Abstract of The United States*, 109th Edition, U.S. Dept. of Commerce. The annual construction cost inflation rate used for plant/well field surface facilities is 1.43% based on Handy-Whitman public utility indexes for electric light and power plant construction. The annual manufacturing cost inflation rate for the cable portion of the project is 1.83% based on the producer price indexes for machinery and equipment.

[illegible]

# NEA - GEOTHERMAL PROJECT COST ESTIMATES

This section describes how the geothermal project cost figures were developed for use in the analysis. Costs were developed for the construction of 25 net MW and 50 net MW geothermal power plants, the manufacture and laying of submarine cable, and the construction of overhead transmission lines and associated facilities. In estimating this cost NEA used available information from various Federal, State and Private industry sources and reports, and have followed the route and system requirements found in the DAHI and previous NEA reports.

## GEOTHERMAL POWER PLANTS

Costs were developed for two sizes of power plants, 25 net MW (27.5 gross MW) and 50 net MW (55 gross MW). The DAHI report uses 25 MW plants in its analysis but indicates that current conjecture is for ten 50 MW plants. To estimate power plant costs we used the CENTPLANT computer program. This program was created specifically for estimating geothermal development costs and is designed to estimate the capital costs of geothermal plant and wellfield surface facilities having 10 to 100 MW capacity. The estimates are based upon the temperature of the resource, its flow rate, and the location and difficulty of developing the resource. CENTPLANT was originally developed by the Oregon Department of Energy with cost information and engineering formulas provided by Bechtel National, Inc. A copy of the program is available from the Oregon Department of Energy or the Bonneville Power Administration.

The CENTPLANT program develops costs for the following components:

Geothermal Power Plant

Turbine inlet valves and strainers
Turbine and generator
Condenser (surface type)
Condensate pumps
Cooling towers
Circulating water pumps and piping
Main transformer
Switchyard
Process piping

Geothermal Power Plant - cont'd

Plant electrical equipment

Instrumentation and controls

Site preparation

Turbine and control building

Balance of plant systems

Construction labor

Indirect field costs (temporary construction facilities, miscellaneous construction services, construction equipment and supplies, field office, preliminary checkout and acceptance testing, and startup).

Wellfield

Production wellpad piping and equipment downstream from wellhead shutoff valves

Production wellpad instrumentation and controls

Steam or hot water transmission pipelines

Flash tanks (flashed steam plants only)

Steam release facility

Startup system for production wells (flashed steam plants only)

Reinjection pumps

Reinjection pipeline

Reinjection piping and equipment

Reinjection instrumentation and controls

Wellfield electrical system

Wellfield distributed digital automatic control system

Construction labor

Engineering, procurement, and construction management

Indirect field costs

Production and reinjection island development (clearing, grubbing, grading, etc.)

On-site roads

Inputs Provided By Program User

H2S Abatement

Permits and licenses

Resource assessment and exploration

Production, reinjection, and replacement wells

Owner's engineering, administrative, and general costs

Cost overrun contingency

Costs Not Included In Program

Land or land use costs

Research and development costs

Power transmission lines beyond the AC/DC converter station

The program generates low, mid and high estimates of costs based on built-in engineering factors provided by Bechtel National, Inc. and variable input assumptions provided by the user. The low range estimate does not account for reinjection wells which will be required in the proposed 500 MW project. Therefore, only the mid and high estimates are used in this report. The mid estimate is now referred to as the low estimate using injection wells.

**Input Assumptions**

**Low Estimate (with injection wells)**

- Site preparation and construction camp is required
- 13¢/kWh electricity cost at plant
- 10 miles AC transmission line
- $2.5 million in remaining resource assessment work
- $750,000 for various permits and licenses
- Wells produce at 4 MW per well
- 2/1 Production/Injection well ratio
- 3/1 well drilling success ratio
- 100% production well replacement over life of the plant

**High Estimate (with injection wells)**

- Site preparation and construction camp is required
- 13¢/kWh electricity cost at plant
- 10 miles AC transmission line
- $3 million in remaining resource assessment work
- $1 million for various permits and licenses
- Wells produce at 3 MW per well
- 2/1 Production/Injection well ratio
- 3/1 well drilling success ratio
- 100% production well replacement over life of the plant

Production wells are assumed to be 6,000-7,000 feet deep and to cost $2.5 million per well. Injection wells and drywells are estimated to cost $2.0 million per well. The same well costs are used as those found in the DAHI report. See Appendix A for the range of well costs considered.

This study's production to injection well ratio is 2 to 1. The DAHI report assumes a 2.67 to 1 ratio. Based on data for geothermal wells actually drilled in Japan appearing in the Geothermal Resources Council Bulletin of October 1989, a ratio of 1.1 to 1 was experienced. For lack of better information our ratio rests comfortably between the two.

The well drilling success ratio is 3 to 1, while the DAHI report assumes a 4 to 1 ratio. The Japanese experience indicates a ratio of 2.4 to 1. The figure used in this study between the two.

The well replacement rate is 100% over 20 years; the DAHI report rate is also 20 years. Recent reports from The Geysers in California, however, indicate that steam pressure in the wellfields is falling rapidly, and that well life may be only 10 to 15 years instead of the earlier predicted 20 to 30 years. If this proves true for Hawaii, the replacement rate may be 200% on more.

Hydrogen Sulfide ($H_2S$) abatement assumes the use of a Stretford system. The cost is based on a similar cost from The Geysers, Unit 21 abatement system. Unit 21 is 125 MW so the cost has been scaled down to 25 MW and 50 MW using the 0.6 scaling factor found in the DAHI report and brought up to 1990 dollars. According to a 1985 review of a report estimating abatement costs for Hawaii, Thermal Power Company and Bechtel Group Inc., indicated that abatement costs in Hawaii will vary widely since the resource is so variable and will change over time. The estimated abatement costs reviewed by Thermal Power and Bechtel were based on a single set of assumptions and were characterized as being "at the extreme low end of published values for similar plants," such as The Geysers Unit 21.

Based on this criticism and the assumption that geothermal fluids in Hawaii are at least as toxic and corrosive as those in California, the Unit 21 abatement cost figure is used as the low abatement cost for 25 MW and 50 MW plants. The costs are:

| | Low | | High |
|---|---|---|---|
| | | Million $ | |
| 25 MW | 6.46 | | 9.70 |
| 50 MW | 10.34 | | 15.51 |

A 20% cost contingency is added to the plant/wellfield surface facilities, development costs and well drilling costs to cover unexpected costs and cost overruns. Using this contingency level is justified since it agrees with the difference between actual completed plant costs shown in Table 4 and the CENTPLANT generated estimates. Geothermal experts who have studied geothermal development costs agreed that 20% is probably the minimum contingency, while 30% may be more appropriate for a project as ambitious as the Hawaii project[1]

The CENTPLANT generated estimate for dollars per gross kilowatt hour which NEA uses for a 25 net MW (27.5 gross MW) plant is 20% below the average actual cost per gross kilowatt hour of plants constructed in the 20 to 30 MW range. The DAHI report estimate is 52% below the average. For dollars per net kilowatt hour, the percentages are NEA 22% below and DAHI 55% below.

Only one of the three plants listed, shows a construction time for building a geothermal power plant. The figure is higher than estimates of Stone & Webster Engineering Company of Denver, Colorado who estimate 12 months minimum construction time, and 24 months as an average.[2] NEA uses the estimate of 12 months, while the DAHI report estimates 7 months or less construction time per plant.

Table 5 shows the geothermal power plant capital costs estimated by NEA using the CENTPLANT program. See Appendix B for more detail on the CENTPLANT output.

A comparison of NEA and DAHI total development costs for twenty 25 net MW power plants and their required wells is shown in Table 6.

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1/ Alex Sifford, Geothermal Program Manager, Resource Development Division, Oregon Department of Energy.

2/ Alex Sifford, Geothermal Program Manager, Resource Development Division, Oregon Department of Energy.

## Table 4

## GEOTHERMAL PLANT COST COMPARISON

| | Year | Gross Mega-watts | Net Mega-watts | Year Built Cost $M | Year Built $/GR KW | Year Built $/Net KW | Cost $M 1990$ | 1990 $/GR KW | 1990 $/Net KW | Months Const. Time |
|---|---|---|---|---|---|---|---|---|---|---|
| Plants in 20-30MW Range1/ | | | | | | | | | | |
| Bear Canyon | 1989 | 22.0 | 20.0 | 34.8 | 1582 | 1740 | 35.3 | 1605 | 1765 | |
| Roosevelt | 1984 | 23.5 | 20.0 | 36.0 | 1532 | 1800 | 39.2 | 1668 | 1960 | 28 |
| West FordFlat | 1989 | 29.7 | 27.0 | 47.0 | 1582 | 1741 | 47.7 | 1605 | 1766 | |
| Plants in 20-30MW Range | | 75.2 | 67.0 | 117.8 | | | 122.2 | 1625 | 1823 | |
| (25MW) NEA Low | 1990 | 27.5 | 25.0 | | | | 37.3 | 1357 | 1493 | 12 |
| (25MW) NEA High | 1990 | 27.5 | 25.0 | | | | 40.9 | 1488 | 16.6 | 12 |
| (25MW) DAHI | 1990 | 27.5 | 25.0 | | | | 29.4 | 1068 | 1174 | 7 |
| Percent Below Average | | | | | | | | | | |
| (25MW) NEA Low | | | | | | | | 20% | 22% | |
| (25) NEA High | | | | | | | | 9% | 11% | |
| (25MW) DAHI | | | | | | | | 52% | 55% | |

1/ Alex Sifford, Oregon Department of Energy; in the report "Innovative Design of New Generating Plants," by Gordon Bloomqust, John Geyer, and Alex Sifford, produced by the Washington State Energy office for the Bonneville Power Administration, July 1989.

Note: Construction costs were brought up to 1990 dollars using an annual construction cost inflation rate of 1.43%. This rate is based on Handy-Whitman public utility indexes for electric light and power plant construction. See earlier footnote.

## Table 5

## GEOTHERMAL POWER PLANT CAPITAL COST (1990 dollars) $million

| Plant Size (Megawatts) | Low Estimate | High Estimate |
|---|---|---|
| 25 | 107.79 | 129.40 |
| 50 | 187.07 | 227.19 |

Note: Includes initial wells, wellfield surface facilities, power plant, transmission lines, resource assessment, permits, licenses, 20% cost contingency. Does not include replacement wells.

Table 6

COST COMPARISON (M$)
PLANTS AND WELLS

| 25 Net MW Plants Cost Comparison (M$) | Plant/Wellfield Surface Facilities | Wells | Total |
|---|---|---|---|
| **Without Contingency:** | | | |
| DAHI 1986$ | 662.2 | 600.0 | 1262.2 |
| DAHI 1990$ | 700.9 | 600.0 | 1300.9 |
| NEA 1990$ (low estimate) | 984.6 | 675.0 | 1659.6 |
| NEA 1990$ (high estimate) | 1104.6 | 900.0 | 2004.6 |
| **With 20% Contingency:** | | | |
| DAHI 1990$ | 841.1 | 720.0 | 1561.1 |
| NEA 1990$ (low estimate | 1345.9 | 810.0 | 2155.9 |
| NEA 1990$ (high estimate) | 1507.9 | 1080.0 | 2587.9 |
| **With 20% Contingency & Replacement Wells:** | | | |
| DAHI 1990$ | 841.1 | 1440.0 | 2281.1 |
| NEA 1990$ (low estimate) | 1345.9 | 1620.0 | 2965.9 |
| NEA 1990$ (high estimate) | 1507.9 | 2160.0 | 3667.9 |

Note: The 1986 DAHI cost figures are brought up to 1990 levels using inflation rates calculated from indexes found in the *Statistical Abstract of The United States*, 109th Edition, U.S. Dept. of Commerce. The annual construction cost inflation rate used for plant/well field surface facilities is 1.43% based on Handy-Whitman public utility indexes for electric light and power plant construction. The annual manufacturing cost inflation rate for the cable portion of the project is 1.83% based on the producer price indexes for machinery and equipment.

## TRANSMISSION CABLE SYSTEM

### Submarine Transmission Cables

The submarine cable to be used in this project must be able to withstand the rigors of the underwater environment. High pressures at deep depths, tidal flows, currents of uncertain direction and force, steep and difficult terrain, and the corrosive nature of sea water all combine to make the design and construction of a reliable cable system a formidable task. However, there are in operation fully functional and reliable submarine cable systems around the world, and although the Hawaii Cable Project proposes to install its cable system at deeper depths than any of the others, there is little doubt that the design and engineering can be accomplished. The question, is at what cost?

Table 7 gives a basic description of the type of cable thought to be needed for the cable project, and Figure 3 shows its design characteristics in cross section. This specially designed oil containing, pressurized cable would be used for the 42 mile length between Hawaii and Maui (see Table 1, Segments 4H, 1A, 1M).

The 96 mile length from Maui to Oahu (Table 1, Segment 3M), in shallower less treacherous water, will use a combination of solid cable with single and double armored lengths. This cable scenario is in agreement with that proposed by the Pirelli Cable Corporation and found in the DAHI report.

Notes on the cable calculation:

1. The costs of cable manufacturing are from Pirelli Cable Corporation as found in the DAHI report. The cost is in 1986 dollars. These costs are brought up to 1990 dollars using a 1.83% per year inflation factor. See Table 3, footnote 2.

2. The cost of oil pressurization stations is from Pirelli Cable Corporation as found in the DAHI report. The costs are in 1986 dollars. These costs are brought up to 1990 dollars using a 1.83% per year inflation factor. See Table 3, footnote 2.

3. An allowance for slope and bend for the undersea distances is 20% for the Hawaii-Maui segment and 5% for the Maui-Oahu segment.

4. Cost of the cable laying vessel, which will have to be constructed, is from William Bonnet, Hawaii Deep Water Cable Program Manager, in a letter to Nelson Ho, March 10, 1987. The 1987 figure is brought up to 1990 dollars using a 2.28% per year inflation factor. (U.S. Bureau of Labor Statistics, Producer Price Index for transportation equipment).

5. We assumed two helper vessels will be required to assist in laying the cable. We base this assumption on an article appearing in the Geothermal Resources Council Bulletin, December 1989, page 20 which described the deep-water cable test. Besides the cable laying vessel itself, the mother ship of the submersible vessel used to guide and examine the cable, and a monitoring and evaluation vessel to keep track of ocean currents is required in the operation.

6. The cable laying costs and timetable are approximations from the DAHI report.

## Table 7

## GENERAL DESCRIPTION OF THE PREFERRED CABLE

The cable that is currently being evaluated is a self-contained oil-filled (SCOF) cable, with a 300 kVdc voltage, capable of a total transmission load of 250 megawatts (MW) of electric energy.[1] It is 4.7 inches (119.5 mm) in diameter and weighs 24.46 lbs. per foot (36.4 kg per meter) in air and 17.34 lbs per foot (25.8 kg per meter) in water. The current estimated cost of manufacturing the cable is approximately $280 per yard ($93.33 per foot) of cable ($306 per meter).

**Selected Basic Design Characteristics of Cable Design No. 116**

| | |
|---|---|
| Cable Type | SCOF (See Figure 1) |
| Voltage | ±300 KVDC |
| Conductor Cross Section | 1,600 sq mm (2.48 sq in) |
| Total Transmission Load | 500 MW |
| Transmission Load Per Cable | 250 MW |
| Rated Current Per Cable | 833 Amps |
| Conductor Material | Aluminum |
| Oil Duct Diameter | 25 mm (0.98 in) |
| Oil Type: | High Density Synthetic Low Viscosity |
| Number of Cables for System | 2 plus one spare |
| Polarity Reversal | Allowed |
| Conductor Diameter | 52.2 mm (2.06 in) |
| Insulation Thickness | 10.1 mm (0.4 in) |
| Cable Finished Diameter | 119.5 mm (4.70 in) |
| Cable Weight in Air | 36.4 kg/m (24.46 lb/ft) |
| Cable Weight in Water | 25.8 kg/m (17.34 lb/ft) |
| Maximum Oil Feeding Length | 190 km (118.1 mi) |
| Losses at Rated Current Per Cable | 12.4 kW/km |
| Pulling Tension for 7,000 Ft Water Depth (Based on PCC Formula) | 65.1 mt (71.8 t) |
| Maximum Allowable Cable Pulling Tension | 78.7 mt (86.8 t) |
| Corresponding Maximum Water Depth (Based on PCC Formula) | 2,626 m (8,615.5 ft) |
| Minimum Allowable Bending Diameter During Installation: | |
| a–Without Tension | 7.0 m (22.97 ft) |
| b–With 7,000 Ft Pulling Tension | 11.6 m (38.06 ft) |
| c–With Maximum Allowable Pulling Tension | 12.0 m (29.37 ft) |

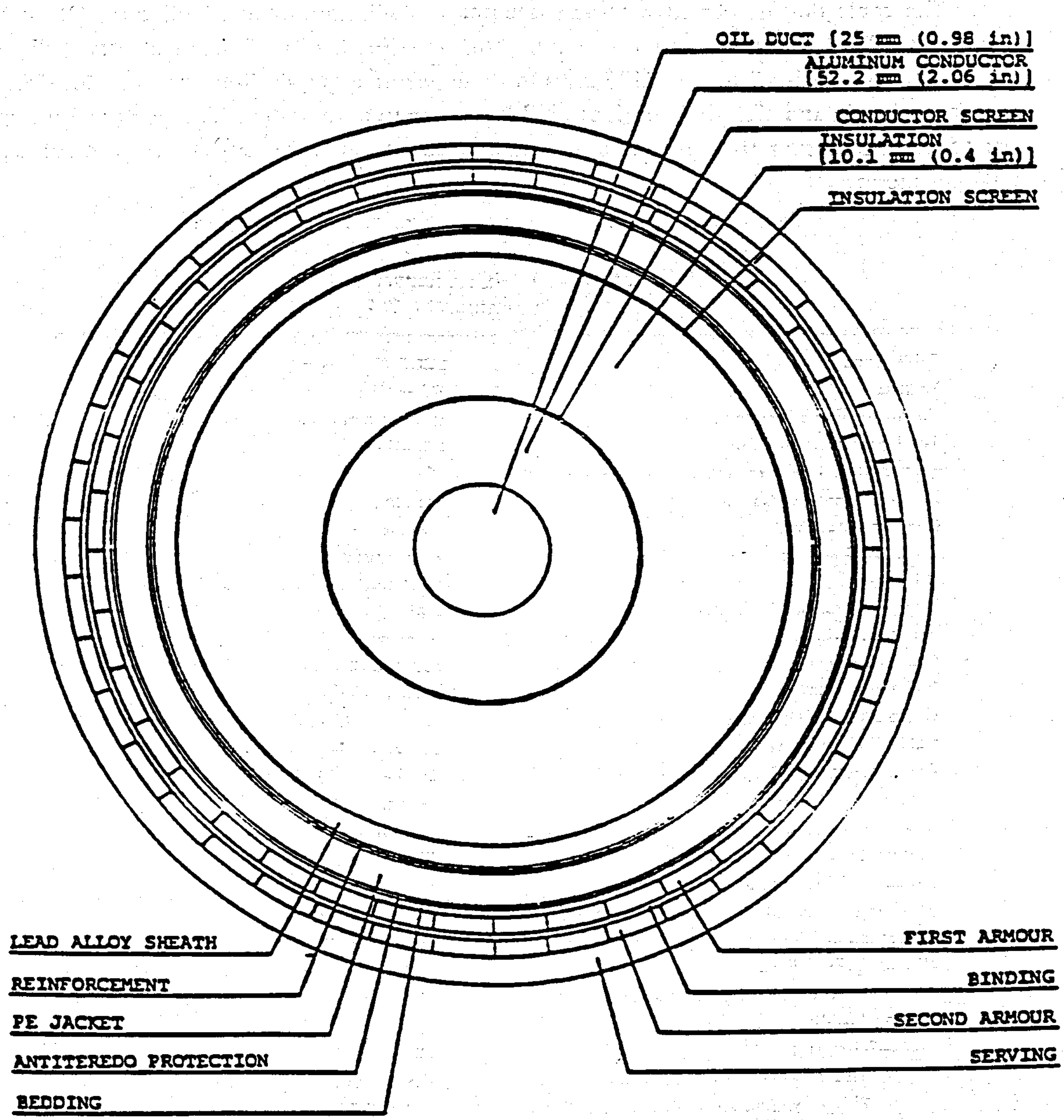
1/ This information has been provided by Parsons Hawaii and HECO.

Source: Parsons Hawaii, Hawaii Deep Water Cable Program Basin Design Criteria Book (April, 1985), p. 4-3

NEA Source: "Alternative Approaches to the Legal, Institutional, and Financial Aspects of Developing an Inter-island Electrical Transmission Cable System," State of Hawaii, Department of Planning and Economic Development, April, 1986.

## Figure 3

### TYPICAL SCOF CABLE CROSS SECTION
### (Dimensions Based on Cable Design Case No. 116)




Source: Pirelli Cable Corp., HDWC Program, October 12, 1983.

NEA Source: "Alternative Approaches to the Legal, Institutional, and Financial Aspects of Developing an Inter-island Electrical Transmission Cable System," State of Hawaii, Department of Planning and Economic Development, April, 1986.

## CABLE MANUFACTURING COST:

**Hawaii-Maui**

3 Cables
42 miles
126 cable miles
20% slope correction factor
151.2 total cable miles
(1986) 85.00 dollars per foot
(1990) 91.39 dollars per foot
(1986) $6,000,000 oil pressurization stations
(1990) $72,959,927 cost for cable
(1990) $6,451,404 oil pressurization stations
(1990) $79,411,331 total for cable & oil stations

**Maui-Oahu**

3 cables
96 miles
288 cable miles
5% slope & bend correction factor
302.4 total cable miles
(1986) 81.25 dollars per foot
(1990) 87.36 dollars per foot
(1990) $139,485,266 cost for cable

**Total Hawaii-Maui-Oahu with 20% Cost Contingency Factor**

(1990) $262,675,916 Total Cost For Both Cables

## CABLE LAYING COST:

Vessel Construction
(1987) $17,600,000
(1990) $18,831,496

Vessel Operation Costs Per Day
$40,000 Main Vessel (1990)
$15,000 Helper Vessel (1990)

**Hawaii-Maui**

3 Cables
42 miles
126 cable miles
20% slope & bend correction factor
151.2 total cable miles
0.33 cable miles per day
458 days to lay cable

$18,327,273 Cost of Main Vessel
$13,745,455 Cost of Helper Vessels (2)

**Maui-Oahu**

3 cables
96 miles
288 cable miles
5% slope & bend correction factor
302.4 total cable miles
0.50 cable miles per day
605 days to lay cable

$24,192,000 Cost of Main Vessel
$18,144,000 Cost of Helper Vessels (2)

2.91 Years to lay cable

**Total Hawaii-Maui-Oahu with 20% Cost Contingency Cost**

(1990) $111,888,268 Total Cost To Lay Both Cables

(1990) $374,564,184 Total Cost Manufacture, Delivery, and Laying of Submarine Cable and Facilities

### Overhead Transmission Lines and Facilities

There will be 108 miles of DC (direct current) transmission line on Hawaii (Table 1, Segments 1H, 2H, 3H), 20 miles on Maui (Table 1 Segment 2M), and 3 miles on Oahu (Table 1, Segment 1O). There will also be a need for new AC transmission lines to connect from the converter stations to the existing grid on Oahu. We estimate this length at 15 miles.

**Overhead Transmission Lines and Facilities:**

| | |
|---|---|
| 500,000 | KW |
| $180 | Cost Per Kilowatt |
| $90,000,000 | Cost For Termination Facilities and AC/DC Conversion Stations |
| 2 | Stations |
| $180,000,000 | Total Cost For Termination Facilities and AC/DC Conversion Stations |
| $240,000 | Cost/mile Overhead DC Transmission Lines |
| 108 | Miles Hawaii |
| 20 | Miles Maui |
| 3 | Miles Oahu |
| 2 | Lines |
| 262 | Total Miles |
| $62,880,000 | Total Cost Overhead DC Transmission Lines |
| $360,000 | Cost/mile Overhead AC Transmission Lines |
| 15 | Miles Hawaii |
| $5,400,000 | Total Cost Overhead DC Transmission Lines |
| 20% | Cost Contingency Factor |
| $1,000,000 | Environmental Impact Statement |

**(1990) $298,936,000 Total Cost For Overhead Transmission Lines and Facilities with 20% Cost Contingency**

Notes on the transmission facilities calculation:

1. The cost of AC and DC transmission lines is from Bonneville Power Administration (BPA) engineers in Portland, Oregon. The cost for AC transmission lines is more than for DC transmission lines because AC transmission requires three cables instead of two as is the case for DC. This third cable requires that the towers be larger and the right-of-way wider for AC than for DC.

2. Two AC/DC conversion stations and termination facilities will be required for the project. One will be located at the source of power generation on Hawaii and the other on Oahu where the DC power lines join the AC power distribution grid. BPA engineers estimate that a termination and conversion facility for a 500 MW system using solid state converters and state of the art switching gears and transformers will cost between $80 million and $100 million. (B.C. Hydro engineers estimate the cost at closer to $125 million per station.)

A comparison of NEA and DAHI total costs for submarine and overland power transmission cables and facilities is shown in Table 8:

Table 8

COST COMPARISON (M$)
TRANSMISSION CABLES AND FACILITIES

| Total Cost All Cable & Overhead | Total |
|---|---|
| No cost contingency<br>No cost for cable laying vessel<br>No slope or curvature allowance for cable | |
| DAHI 1986 $ | $413.3 |
| DAHI 1990 $ | $444.4 |
| With 20% cost contingency<br>No cost for cable laying vessel<br>No slope or curvature allowance for cable | |
| DAHI 1990 $ | $533.2 |
| With 20% cost contingency<br>Includes cost for cable laying vessels<br>Includes slope and curvature allowance for cable | |
| NEA 1990 $ | $673.5 |

A comparison of NEA and DAHI total project development costs for twenty 25 net MW plants is shown in Table 9:

Table 9
**PROJECT DEVELOPMENT COST COMPARISON**

| 25 Net MW Plants Cost Comparison (M$) | Plant/Wellfield Surface Facilities | Wells | Cables | Total Cost |
|---|---|---|---|---|
| **Without Contingency:** | | | | |
| DAHI 1986$ | 662.2 | 600.0 | 413.3 | 1675.5 |
| DAHI 1990$ | 700.9 | 600.0 | 444.4 | 1745.3 |
| NEA 1990$ (low estimate) | 984.6 | 675.0 | 561.4 | 2221.0 |
| NEA 1990$ (high estimate) | 1104.6 | 900.0 | 561.4 | 2566.0 |
| **With 20% Contingency:** | | | | |
| DAHI 1990$ | 841.1 | 720.0 | 533.2 | 2094.3 |
| NEA 1990$ (low estimate) | 1345.9 | 810.0 | 673.5 | 2829.4 |
| NEA 1990$ (high estimate) | 1507.9 | 1080.0 | 673.5 | 3261.4 |
| **With 20% Contingency & Replacement Wells:** | | | | |
| DAHI 1990$ | 841.1 | 1440.0 | 533.2 | 2814.3 |
| NEA 1990$ (low estimate) | 1345.9 | 1620.0 | 673.5 | 3639.4 |
| NEA 1990$ (high estimate) | 1507.9 | 2160.0 | 673.5 | 4341.4 |

**<u>NEA Project Capital Cost Estimate</u>**

**20% Contingency**
**Includes Replacement Wells**
**(1990 Dollars)**

| | |
|---|---|
| (20)25 net MW plants | |
| Low | $3.64 Billion |
| High | $4.34 Billion |
| (10)50 net MW plants | |
| Low | $3.35 Billion |
| High | $4.03 Billion |

**<u>NEA Project Capital Cost Estimate</u>**

**30% Contingency**
**Includes Replacement Wells**
**(1990 Dollars)**

| | |
|---|---|
| (20)25 net MW plants | |
| Low | $3.89 Billion |
| High | $4.65 Billion |
| (10)50 net MW plants | |
| Low | $3.56 Billion |
| High | $4.30 Billion |

# NEA - OIL AND SOLAR/OIL POWER PLANT COST ESTIMATES

## OIL PLANTS

The capital cost for the oil fired power plants used in this analysis is $800 per kilowatt in 1990 dollars. This figure was derived from two sources. The 1986 preliminary report from Decision Analysts Hawaii, Inc. uses a figure of $752 per kilowatt for its oil fired power plants. This figure is in 1986 dollars. The California Energy Commission in its October 1988 Energy Technology States Report cites the figure $750 per kilowatt in 1985 dollars. The average of both these figures in 1986 dollars is $756 per kilowatt. Bringing this figure up to 1990 dollars using the 1.43% annual inflation factor from the Handy-Whitman public utility index for electric light and power plant construction costs gives us a base capital cost of $800 per kilowatt. Using this base cost we calculated the total cost per 100 net MW plant as:

| | |
|---|---|
| $800 | per kilowatt base capital cost |
| 110 | gross MW plant size (100 net MW + 10% loss allowance) |
| $88,000,000 | plant base cost (110 MW) |
| 20% | cost contingency |
| $105,600,000 | plant cost with contingency |
| | |
| 10 | miles transmission line |
| $360,000 | cost per mile |
| $3,600,000 | cost per 10 miles |
| 20% | cost contingency |
| $4,320,00 | transmission line cost |
| | |
| **$109,920,000** | **total plant cost** |

This is the oil plant capital cost used in the analysis.

## SOLAR/OIL PLANTS

The cost for a solar/oil fired combination (hybrid) power plant comes from Luz International, a builder and developer of solar thermal electric power plants. Luz International operates the largest solar facility ever built (200 MW in the Mohave Desert region of Southern California) and the source of an estimated 90% of the worlds solar electricity. Luz supplies solar thermal generated electricity to the Southern California Edison power company. Their system is described below:[1]

> Luz's *Solar Electric Generating Systems* (SEGS) use trough mirror assemblies that individually track the sun by way of sophisticated microprocessors and highly precise sun-sensing instruments. The mirrors reflect sunlight onto stainless steel heat collecting pipes covered with a custom-designed absorptive coating.
>
> Inside the pipes, a heat transfer fluid ( a synthetic oil) absorbs and transports the thermal energy to a conventional boiler, which converts water to steam. The steam is then superheated with additional solar thermal energy and powers a steam turbine generator connected to the utility's power grid. On cloudy days or during evening hours, steam is generated by a natural gas boiler that runs the same turbine. The system can also operate in a hybrid mode, using both solar thermal heat and natural gas to generate steam from two separate boilers to run the common turbine.
>
> The natural gas boiler is available to power the turbine generator in order to ensure uninterrupted power during peak demand periods. This makes solar thermal plants more reliable, and therefore more attractive to utilities, according to Luz, because they can guarantee power at all times.

Representatives from Luz International[2] indicated that a hybrid solar/oil generating facility similar to the solar/gas facilities now operating in California was a possible power generation option for Hawaii. The cost of the facility would be higher in Hawaii since the solar radiation availability (insolation) is lower. For example, the average annual mean daily solar radiation based on four collection stations in Southern California is about 1850 BTU's per square foot.[3] In Hawaii the

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1/ *Power Surge The Status and Near Term Potential of Renewable Energy Technologies*, By Nancy Rader, for the Public Citizen Critical Mass Energy Project, May 1989.

2/ Phone conversation with Howard Hampton, Luz International, LTD., February, 1990.

3/ The solar availability figures (insolation) come from the U.S. Dept. of Energy publication *Input Data for Solar Systems*, by V. Cinquemani, J.R. Owenby Jr., and R.G. Baldwin, November 1978.

average annual mean daily solar radiation available, based on four collection stations, is about 1550 BTU's per square foot. Consequently, more solar collector surface area would be required in Hawaii to collect the same amount of available energy as in Southern California. Since solar collectors are the major component of the solar facility the cost would increase accordingly. Below is a comparison that shows the estimated difference in cost between a 100 net MW solar/oil plant built in Southern California based on Luz International cost estimates[1] and a 100 net MW plant built in Hawaii.

## COMPARISON OF SOLAR/OIL PLANT COSTS- CALIFORNIA/HAWAII

**California**

| | |
|---|---|
| solar costs | 100 net MW California |
| 1,850 | btu/sq. ft insolation |
| 3,413,000 | btu per MW |
| 1,845 | sq. ft collector to capture 1 gross MW |
| 110 | gross MW |
| 202,935 | sq. ft. collector for 110 gross MW |
| 0.35 | conversion efficiency |
| 579,815 | sq. ft. collector for 110 gross MW |
| 1,988 | $/kW for solar collectors |
| 377 | $/for sq. ft. solar collector |
| 218,680,000 | $ for solar collectors |
| 250 | $ for common generator |
| 2238 | $ kW for solar component |
| 550 | kW for oil component |
| 2,788 | $ kW for solar/oil plant |

**Hawaii**

| | |
|---|---|
| solar costs | 100 net MW Hawaii |
| 1,550 | btu/sq. ft insolation |
| 3,413,000 | btu per MW |
| 1,845 | sq. ft collector to capture 1 gross MW |
| 110 | gross MW |
| 242,213 | sq. ft. collector for 110 gross MW |
| 0.35 | conversion efficiency |
| 692,037 | sq. ft. collector for 110 gross MW |
| 2,373 | $/kW for solar collectors |
| 377 | $/for sq. ft. solar collector |
| 261,005,161 | $ for solar collectors |
| 250 | $ for common generator |
| 2,623 | $ kW for solar component |
| 550 | kW for oil component |
| 3173 | $ kW for solar/oil plant |

---

1/ Northwest Power Planning Council, Staff Issue Paper 89-46, *Solar Electric Resources*, November, 1989.

Using this base cost we calculated the total cost per 100 MW solar/oil hybrid power plant as:

| | |
|---|---|
| $3173 | per kilowatt base capital cost |
| 110 | gross MW plant size (100 net MW + 10% loss allowance) |
| $349,030,000 | plant base cost (110 MW) |
| 20% | cost contingency |
| $418,836,000 | plant cost with contingency |
| | |
| 10 | miles transmission line |
| $360,000 | cost per mile |
| $3,600,000 | cost per 10 miles |
| 20% | cost contingency |
| $4,320.00 | transmission line cost |
| **$423,156,000** | **total plant cost** |

This is the solar/oil plant capital cost used in the analysis.

In the analysis it is assumed the solar component of the plant contributes 30% of the total power output. The oil component provides 70%.

The island of Hawaii is the product of volcanic eruptions that have occurred over millions of years. Eruptive activity is currently occurring and as stated by the authors of a recent U.S.G.S. Publication:[1]

> "Similar eruptions have continued into historical time on the islands of Hawaii and Maui and undoubtedly will occur in the future, especially on Kilauea and Mauna Loa Volcanoes. Most Hawaiian eruptions form lava flows that endanger chiefly property; explosive eruptions are relatively rare but are more likely to threaten people. As intensive land development expands toward areas of relatively high hazard, the threat to life and property will increase accordingly."

The current eruption which began in 1982 and has continued through the present, has covered well over 12,000 acres and caused damages of more than $11 million. It is the same eruption which completely covered what was to have been a geothermal development site and prompted a land exchange with the state, insuring geothermal proponents the pursuit of their development objective.

Figure 4 shows the five major volcanoes that make up the island of Hawaii. Of the five, the two most active are Mauna Loa and Kilauea. Tables 10 and 11 list the eruptive activity that has occurred on Mauna Loa and Kilauea Volcanoes in the recent past. Kilauea has recorded 65 eruptions in the last 233 years and has an eruption interval of about 3.5 years. Mauna Loa has had 37 eruptions in 152 years averaging 4 years between eruptions. Kilauea, currently erupting, is the most active of the two. The type and pattern of its volcanic activity is shown in Figures 5, 6, and 7.

Areas along the faults and rifts of Kilauea and around other areas of potential volcanic activity have been identified by type and level of hazard (Figures 8 and 9). From information the U.S.G.S. has collected, it has developed a series of hazard zone maps and describes them in the following manner:

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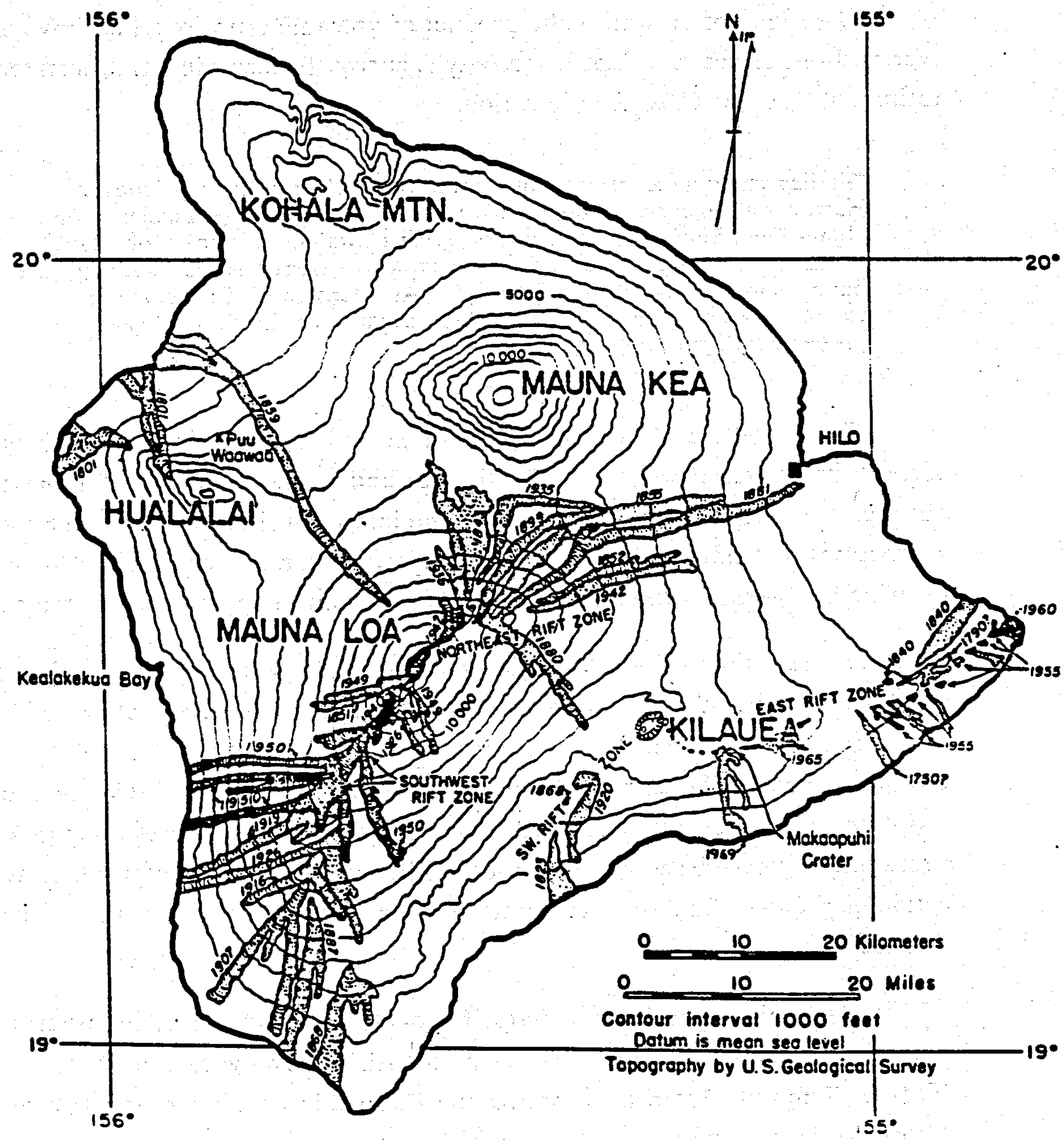
1/ *Volcanism in Hawaii*, Chapter 22, U.S. Geological Survey Professional Paper 1350, 1986.

## Figure 4

### MAP OF THE ISLAND OF HAWAII, SHOWING THE FIVE MAJOR VOLCANOES THAT MAKE UP THE ISLAND, AND THE HISTORIC LAVA FLOWS.




Source: Volcanoes in the Sea, The Geology of Hawaii, Gordon A. Macdonald and Agatin T. Abbott, 1970.

## Table 10

# VOLCANISM IN HAWAII
## Historical Eruptions of Mauna Loa Through May, 1985

[Dashes (---), no data; query (?), questionable data]

| Date eruption began: Year | Date eruption began: Month and day | Duration (days) | Location of major vent(s) | Approximate area (km²) | Approximate volume ($m^3 \times 10^6$) | References |
|---|---|---|---|---|---|---|
| 1832 | June 20 | 21 (?) | Caldera | --- | --- | Stearns and Macdonald, 1946, p. 79. |
| 1843 | January 9 | 95 | Northeast rift | 53 | 191 | Brigham, 1909, p. 63–65; Hitchcock, 1909, p. 84–85. |
| 1849 | May 15 | 15 | Caldera | --- | --- | Coan, 1851; Brigham, 1909, p. 65; Hitchcock, 1909, p. 85 |
| 1851 | August 8 | 21 | -- do -------------------------------- | 18 | 69 | Brigham, 1909, p. 65; Hitchcock, 1909, p. 85–86. |
| 1852 | February 17 | 21 | Caldera, northeast rift | 28 | 107 | Coan, 1852; Brigham, 1909, p. 65–68; Hitchcock, 1909, p. 86–94. |
| 1855 | August 11 | 450 | Northeast rift | 31 | 115 | Brigham, 1909, p. 68–71; Hitchcock, 1909, p. 94–100. |
| 1859 | January 23 | 300 | North flank | 85 | 459 | Davis, 1859; Dana, 1859, 1860; Brigham, 1909, p. 75–80; Green, 1887; Hitchcock, 1909, p. 100–104. |
| 1865 | December 30 | 120 | Caldera | --- | --- | Hitchcock, 1909, p. 104. |
| 1868 | March 27 | 16 | Southwest rift | 24 | 145 | Coan, 1869; Brigham, 1909, p. 100–116; Hitchcock, 1909, p. 104–111; Moore and Ault, 1965, p. 5–7; Fisher, 1968. |
| 1871 | August 1 | 30 | Caldera | --- | --- | Coan, 1871, p. 456. |
| 1872 | August 10 | 60 | -- do -------------------------------- | --- | --- | Brigham, 1909, p. 125; Hitchcock, 1909, p. 111–112. |
| 1873 | January 6 | 2 (?) | -- do -------------------------------- | --- | --- | Brigham, 1909, p. 126; Hitchcock, 1909, p. 112–114. |
| 1873 | April 20 | 547 | -- do -------------------------------- | --- | --- | Brigham, 1909, p. 122–127; Hitchcock, 1909, p. 114–115. |
| 1875 | January 10 | 30 | -- do -------------------------------- | --- | --- | Brigham, 1909, p. 127; Hitchcock, 1909, p. 115; Coan, 1877. |
| 1875 | August 11 | 7 | -- do -------------------------------- | --- | --- | Do. |
| 1876 | February 13 | 1 | -- do -------------------------------- | --- | --- | Brigham, 1909, p. 127; Coan, 1877. |
| 1877 | February 14 | 11 | Caldera, west flank (offshore) | --- | --- | Brigham, 1909, 127–128; Hitchcock, 1909, p. 115–116; Coan, 1877. |
| 1880 | May 1 | 6 | Caldera | --- | --- | Brigham, 1909, p. 133, 145; Hitchcock, 1909, p. 116. |
| 1880 | November 1 | 280 | Northeast rift | 62 | 230 | Brigham, 1909, p. 145–155; Hitchcock, 1909, p. 116–119. |
| 1887 | January 16 | 10 | Southwest rift | 29 | 230 | Brigham, 1909, p. 165–168; Hitchcock, 1909, p. 123–127. |
| 1892 | November 30 | 3 | Caldera | --- | --- | Brigham, 1909, p. 185. |
| 1896 | April 21 | 16 | -- do -------------------------------- | --- | --- | Brigham, 1909, p. 192–196; Hitchcock, 1909, p. 123–130. |
| 1899 | July 4 | 23 | Caldera, northeast rift | 42 | 153 | Brigham, 1909, p. 196–199; Hitchcock, 1909, p. 132–138. |
| 1903 | October 6 | 60 | Caldera | --- | --- | Brigham, 1909, p. 202–204; Hitchcock, 1909, p. 138–139. |
| 1907 | January 9 | 15 | Caldera, southwest rift | 21 | 76 | Brigham, 1909, p. 206–209; Hitchcock, 1909, p. 142–146. |
| 1914 | November 25 | 48 | Caldera | --- | --- | Jaggar, 1947, p. 99. |
| 1916 | May 19 | 14 | Southwest rift | 17 | 61 | Jaggar, 1947, p. 104. |
| 1919 | September 26 | 42 | Caldera, southwest rift | 24 | 268 | Jaggar, 1919, 1947, p. 125–133; Moore and Ault, 1965, p. 7. |
| 1926 | April 10 | 15 | -- do -------------------------------- | 35 | 115 | Jaggar, 1926, 1947, p. 171–173. |
| 1933 | December 2 | 17 | Caldera | 5 | 76 | Jaggar, 1947, p. 195–196. |
| 1935 | November 21 | 42 | Caldera, northeast rift | 36 | 122 | Jaggar, 1947, p. 197–200. |
| 1940 | April 7 | 133 | Caldera | 10 | 76 | Macdonald, 1954; Macdonald and Abbott, 1970, p. 57–60. |
| 1942 | April 26 | 15 | Caldera, northeast rift | 28 | 76 | Macdonald, 1954; Macdonald and Abbott, 1970, p. 60–65. |
| 1949 | January 6 | 145 | Caldera | 15 | 59 | Macdonald and Orr, 1950; Finch and Macdonald, 1951; Macdonald and Abbott, 1970, p. 65–67. |
| 1950 | June 1 | 23 | Southwest | 91 | 460 | Finch and Macdonald, 1953; Macdonald, 1954; Macdonald and Abbott, 1970, p. 9–11. |
| 1975 | July 5 | 1 | Caldera, southwest and northeast rifts | [illegible] | [illegible] | Lockwood and others, chapter [illegible], [illegible] |
| 1984 | March 25 | 22 | Caldera, southwest rift, and, primarily, northeast rift | 48 | 220 | Lockwood and others, chapter 19, 1985. |

Source: Volcanism In Hawaii, U.S. Geological Survey Professional Paper 1350.

## Table 11

# VOLCANISM IN HAWAII
## Historical Eruptions of Kilauea Through May, 1985

[Dashes (---), no data; query (?), questionable data]

| Date eruption began Year | Month and day | Duration (days) | Location of major vent(s) | Approximate area (km²) | Approximate volume (m³ × 10⁶) | References |
|---|---|---|---|---|---|---|
| 1750(?) | --- | --- | East rift | 4.1 | 14.9 | Holcomb, chapter 12, 1980. |
| 1790(?) | --- | --- | -- do | 7.9 | 28.8 | Holcomb, chapter 12, 1980. |
| 1790 | November (?) | --- | Caldera (explosive) | (Blocks lapilli, ash) | --- | Brigham, 1909, p. 36–39; Hitchcock, 1909, p. 165–167; Swanson and Christiansen, 1973; Decker and Christiansen, 1984. |
| 1823 | --- | --- | Southwest rift | 10.0 | 11.5 | Hitchcock, 1909, p. 163; Stearns, 1926. |
| 1823 | --- | 101 yr (intermittent) | Caldera, Halemaumau | 8.2 | 2,000.0 | Ellis, 1827, p. 163–176; Brigham, 1909, p. 40–222; Hitchcock, 1909, p. 179–182, 186–188, 191–194, 198–206, 210–260; Jaggar, 1947, p. 9–169, 216–314. |
| 1832 | January 14 | --- | East rim of caldera | --- | --- | Brigham, 1909, p. 46; Hitchcock, 1909, p. 182–185. |
| 1840 | May 30 | 26 | East rift | 17.1 | 215.0 | Coan, 1841; Brigham, 1909, p. 50–55; Hitchcock, 1909, p. 158–190. |
| 1868 | April 2 | --- | Kilauea Iki | .2 | --- | Brigham, 1909, p. 106–110; Hitchcock, 1909, p. 207. |
| 1868 | April 2 | --- | Southwest rift | .1 | .2 | Brigham, 1909, p. 109–119; Hitchcock, 1909, p. 207–210; Coan, 1869. |
| 1877 | May 4 | 1 | Caldera wall | --- | --- | Brigham, 1909, p. 131–132; Hitchcock, 1909, p. 217. |
| 1877 | May 21 (?) | --- | Keanakakoi | .1 | --- | Brigham, 1909, p. 132; Hitchock, 1909, p. 217. |
| 1884 | January 22 | 1 | East rift (submarine) | --- | --- | Stearns and Macdonald, 1946, p. 111; Macdonald and Abbott, 1970, p. 75. |
| 1879 | July 14 | 1 (?) | Distinct episodes of Halemaumau overflows and (or) caldera fissure outbreaks. These are part of the 1823 101-year-long summit eruption. Earlier lava buried; lava from those episodes locally exposed in caldera. | --- | --- | Brigham, 1909, p. 133, 140; Hitchcock, 1909, p. 219. |
| 1882 | September | 3 yr | | --- | --- | Brigham, 1909, p. 156–158; Hitchcock, 1909, p. 221–226. |
| 1888 | July | 310 | | --- | --- | Dana, 1890, p. 123. |
| 1892 | April | 730 (intermittent) | | --- | --- | Brigham, 1909, p. 184–191. |
| 1918 | February 23 | 14 | | .1 | .2 | Jaggar, 1947, p. 112. |
| 1919 | February 7 | 294 | | 4.1 | 26.0 | Jaggar, 1947, p. 118–125. |
| 1921 | January | 60 (approx) | | 2.0 | 6.7 | Jaggar, 1947, p. 149–151. |
| 1919 | December 15 | 221 | Southwest rift (Mauna Iki) | 13.0 | 47.0 | Jaggar, 1947, p. 137–146. |
| 1922 | May 28 | 2 | East rift (Makaopuhi, Napau) | .1 | --- | Jaggar, 1947, p. 155–157. |
| 1923 | August 25 | 7 | East rift | .5 | .1 | Jaggar, 1947, p. 161. |
| 1924 | May 10 | 17 | Caldera (explosive) | (Blocks) | --- | Jaggar and Finch, 1924; Jaggar, 1947, p. 162–168, 205–259; Decker and Christiansen, 1984. |
| 1924 | July 19 | 11 | Halemaumau | .05 | .24 | Jaggar, 1947, p. 168–169. |
| 1927 | July 7 | 13 | -- do | .1 | 2.42 | Jaggar, 1947, p. 175–176. |
| 1929 | February 20 | 2 | -- do | .15 | 1.47 | Jaggar, 1947, p. 180–181. |
| 1929 | July 25 | 4 | -- do | .2 | 2.75 | Jaggar, 1947, p. 181–182. |
| 1930 | November 19 | 19 | -- do | .23 | 6.48 | Jaggar, 1947, p. 185–186. |
| 1931 | December 23 | 14 | -- do | .3 | 7.37 | Jaggar, 1947, p. 186–189. |
| 1934 | September 6 | 33 | -- do | .4 | 7.26 | Jaggar, 1947, p. 197. |
| 1952 | June 27 | 136 | -- do | .6 | 49.0 | Macdonald, 1955, 1959. |
| 1954 | May 31 | 3 | Halemaumau, caldera | 1.1 | 6.5 | Macdonald, 1959; Macdonald and Eaton, 1957. |
| 1955 | February 28 | 88 | East rift | 15.8 | 92.0 | Macdonald, 1959; Macdonald and Eaton, 1964. |
| 1959 | November 14 | 36 | Kilauea Iki | .6 | 51.0 | Richter and Eaton, 1960; Macdonald, 1962; Richter and others, 1970. |
| 1960 | January 13 | 36 | East rift | 10.6 | 120.0 | Do. |
| 1961 | February 24 | 1 | Halemaumau | .05 | .02 | Richter and others, 1964. |
| 1961 | March 3 | 22 | -- do | .8 | .27 | Do. |
| 1961 | July 10 | 7 | -- do | 1.0 | 13.2 | Do. |
| 1961 | September 22 | 3 | East rift | .8 | 2.3 | Do. |
| 1962 | December 7 | 2 | -- do | [illegible] | [illegible] | Moore and Krivoy, 1964. |
| 1963 | August 21 | 2 | East rift (Alae) | [illegible] | .04 | Peck and Kinoshita, 1976. |
| 1963 | October 5 | 1 | East rift | 3.4 | 6.9 | Moore and Koyanagi, 1969. |
| 1965 | March 5 | 10 | East rift (Makaopuhi, Napau) | 7.8 | 18.0 | Wright and others, 1968. |
| 1965 | December 24 | 1 | East rift (Alae and vicinity) | .6 | .9 | Fiske and Koyanagi, 1968. |
| 1967 | November 5 | 251 | Halemaumau | .65 | 84.1 | Kinoshita and others, 1969. |
| 1968 | August 22 | 5 | East rift | .03 | .04 | Jackson and others, 1975. |

## Table 11 Cont'd.

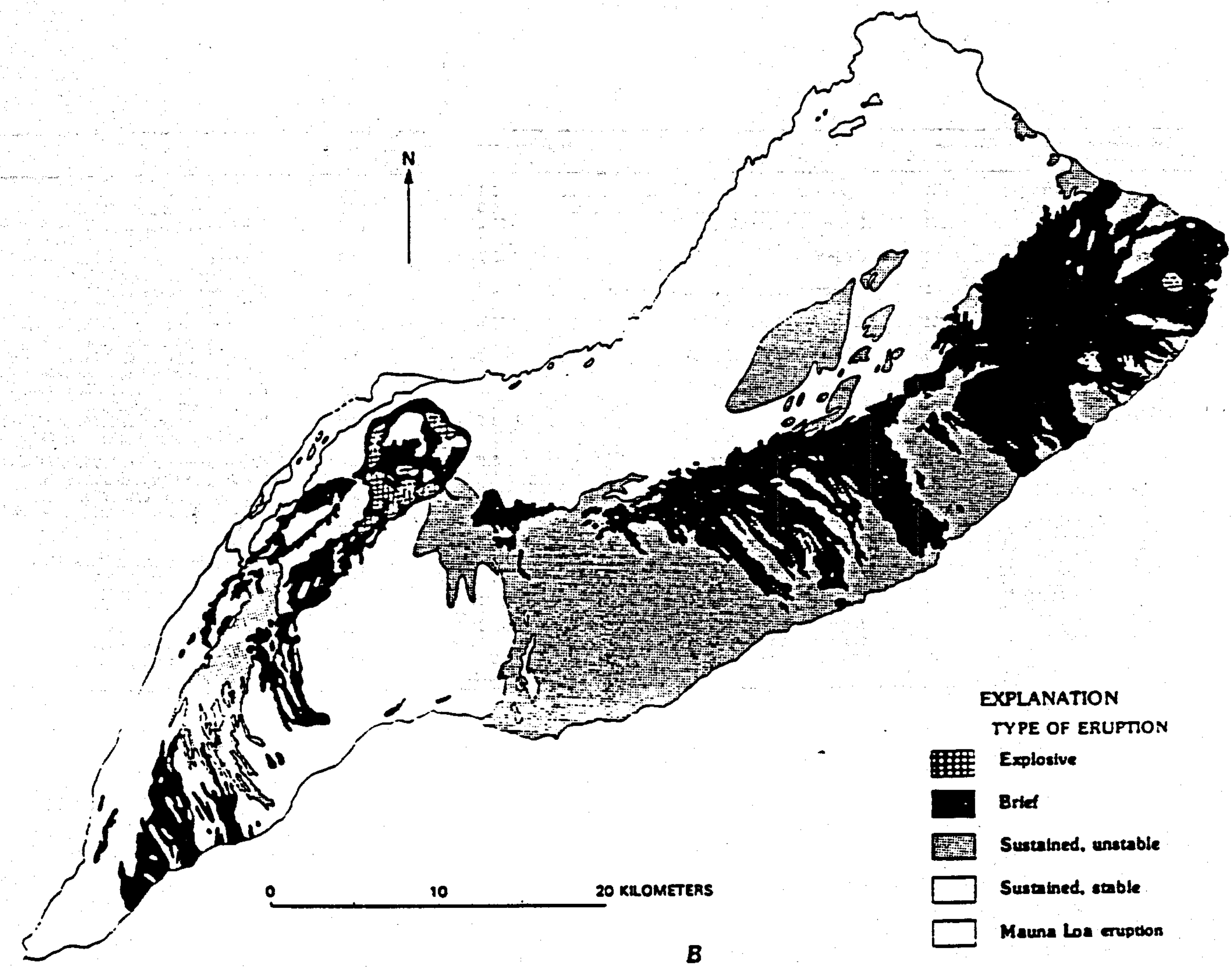
# VOLCANISM IN HAWAII
## Historical Eruptions of Kilauea Through May, 1985

| Date eruption began Year | Month and day | Duration (days) | Location of major vent(s) | Approximate area (km²) | Approximate volume (m³ x 10⁶) | References |
|---|---|---|---|---|---|---|
| 1968 | October 7 | 15 | -- do | 2.1 | 7.0 | Do. |
| 1969 | February 22 | 6 | -- do | 6.0 | 17.0 | Swanson and others, 1976b. |
| 1969 | May 24 | 875 | East rift (Mauna Ulu) | 50.0 | 185.0 | Swanson and others, 1971, 1979; Peterson and others, 1976, p. 647–648. |
| 1971 | August 14 | 1 | Caldera | 2.0 | 10.0 | Peterson and others, 1976, p. 649–650; Duffield and others, 1982. |
| 1971 | September 24 | 5 | Halemaumau, caldera, southwest rift | 4.0 | 8.0 | Peterson and others, 1976, p. 650; Duffield and others, 1982. |
| 1972 | February 3 | 455 | East rift (Mauna Ulu) | 35.0 | 125.0 | Peterson and others, 1976, p. 651–652; Tilling and others, chapter 16. |
| 1973 | May 5 | 1 | East rift (Pauahi, Hiiaka) | .14 | 1.0 | Peterson and others, 1976, p. 651–652; Tilling and others, chapter 16. |
| 1973 | May 7 | 187 | East rift (Mauna Ulu) | .5 | 2.5 | Peterson and others, 1976, p. 652; Tilling and others, chapter 16. |
| 1973 | November 10 | 30 | East rift (Pauahi and vicinity) | 1.5 | 3.0 | Peterson and others, 1976, p. 652–653; Tilling and others, chapter 16. |
| 1973 | December 12 | 222 | East rift (Mauna Ulu) | 8.0 | 30.0 | Peterson and others, 1976, p. 653–654; Tilling and others, chapter 16. |
| 1974 | July 19 | 3 | Caldera, Keanakakoi, and vicinity) | 3.2 | 10.0 | Peterson and others, 1976, p. 656; Lockwood and others, chapter 19. |
| 1974 | September 19 | 1 | Halemaumau, caldera | 1.1 | 11.0 | Do. |
| 1974 | December 31 | 1 | Southwest rift, Koae fault system | 7.5 | 15.0 | Do. |
| 1975 | November 29 | 1 | Halemaumau, caldera | --- | .25 | Tilling and others, 1976, p. 15–17. |
| 1977 | September 12 | 20 | East rift | 8.0 | 35.0 | Moore and others, 1980. |
| 1979 | November 16 | 1 | East rift (Pauahi and vicinity) | .17 | .7 | Banks and others, 1981. |
| 1980 | March 11 | 1 | East rift (near Mauna Ulu) | .0001 | .000003 | |
| 1982 | April 30 | 1 | Halemaumau, caldera | .25 | .5 | Banks and others, 1983. |
| 1982 | September 23 | 1 | South outer caldera | .75 | 4.0 | Banks and others, 1983. |
| 1983 | January 3 | continuing (August 1986) | East rift, Puu Oo | 40 (approx) | 350 (approx) | Wolfe and others, chapter 17. |

Source: Volcanism In Hawaii, U.S. Geological Survey Professional Paper 1350.

## Figure 5

## TYPE OF ERUPTIVE BEHAVIOR OF KILAUEA VOLCANO

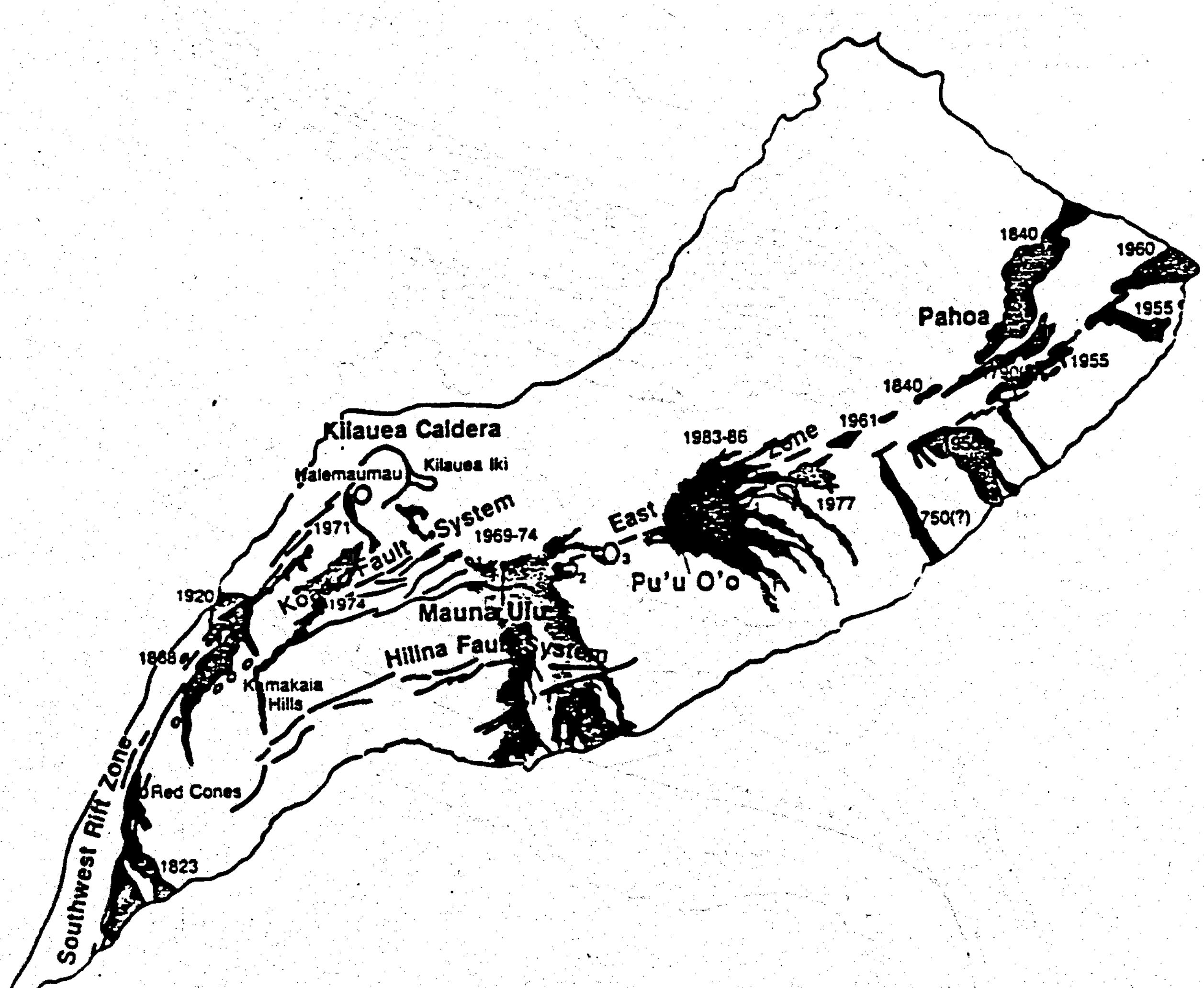



Source: Volcanism In Hawaii, U.S. Geological Survey Professional Paper 1350.

Figure 6

**KILAUEA VOLCANO SHOWING THE LOCATION OF THE SUMMIT CALDERA, TWO ACTIVE RIFT ZONES, THE KOAE AND HILINA FAULT SYSTEMS, AND THE LOCATION OF HISTORIC ERUPTIONS ON THE RIFT ZONES.**

**THE SUMMIT CALDERA FLOOR IS COVERED BY LAVAS ERUPTED BETWEEN 1885 AND 1982.**



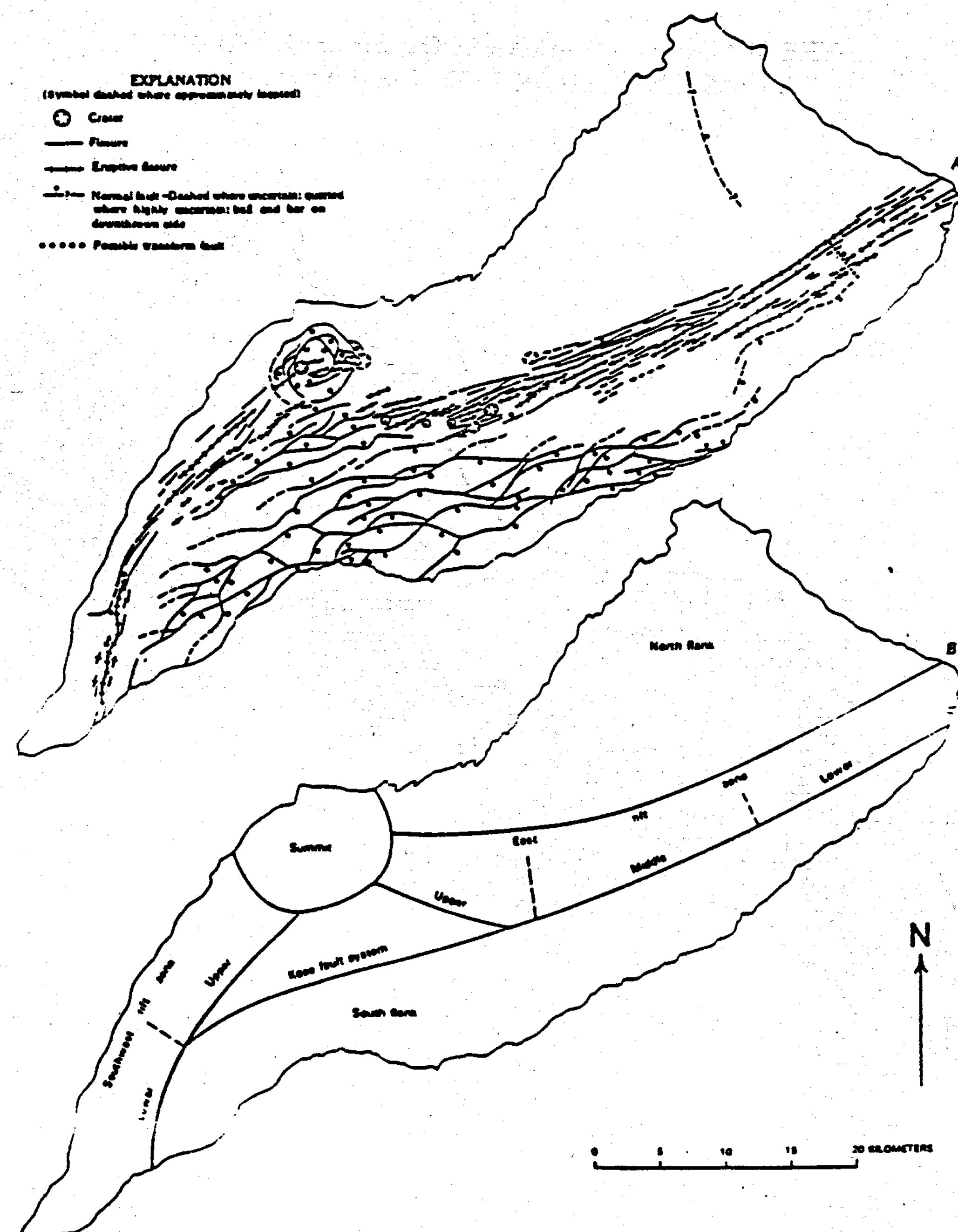

Source: Earthquakes and Volcanoes, U.S. Geological Survey, (formerly Earthquake Information Bulletin) Vol. 18, No. 1, 1986.

## Figure 7

## ERUPTIVE HISTORY AND LONG-TERM BEHAVIOR OF KILAUEA VOLCANO

**Structure of Kilauea**

**A. Mapped structures, simplified from Holcomb (1980b).**
**B. Structural subdivisions, modified from Swanson and others (1976a).**




Source: Volcanism In Hawaii, U.S. Geological Survey Professional Paper 1350.

"The hazard-zone maps distinguish areas in which the general level of hazard is different from that of adjacent areas. However, the level of hazard can vary considerably within any hazard zone, either gradually or abruptly. Direct volcanic hazards, for example, decrease in magnitude gradually across zones away from active vents. For such hazards as lava flows, the frequency with which a specific site is affected decreases with increasing distance; for other hazards such as tephra and gases, the severity of effects diminishes gradually with increasing distance. Such gradational changes in the hazard may extend across an entire zone.

Hazard zones are based chiefly on the assumption that future eruptions will be like those in the past that are known from oral and written histories and from geologic investigations. Some kinds and scales of eruptive events could occur that are not foreseen by these hazards assessments."

According to Dr. Richard Moore of the U.S.G.S., Hawaiian Volcano Observatory, the two most critical hazards to geothermal development are lava flows and ground subsidence.[1] Dr. Moore believes that earthquakes are also a hazard but that structures can be built to withstand them. However, he notes that surface pipe systems would be in danger and could be easily ruptured.

The area in which the proposed geothermal development is to be located is shown in Figure 8. According to U.S.G.S. studies, this is an area of high risk due to volcanic lava flows. The cross-hatching shows the general area in which the power plants will be located, and the line crossing the island shows the preferred route of the proposed power transmission lines.

The U.S.G.S. report cited earlier explains its lava flow hazard zone maps in the following way:

"Hazard zones for lava flows are based chiefly on lava-flow coverage of different areas during specific time periods. The zones are also based partly on the current structural conditions within the volcanoes, on fault scarps and other topographic features that would limit the distribution of lava flows, and on the frequency of past eruptive events."

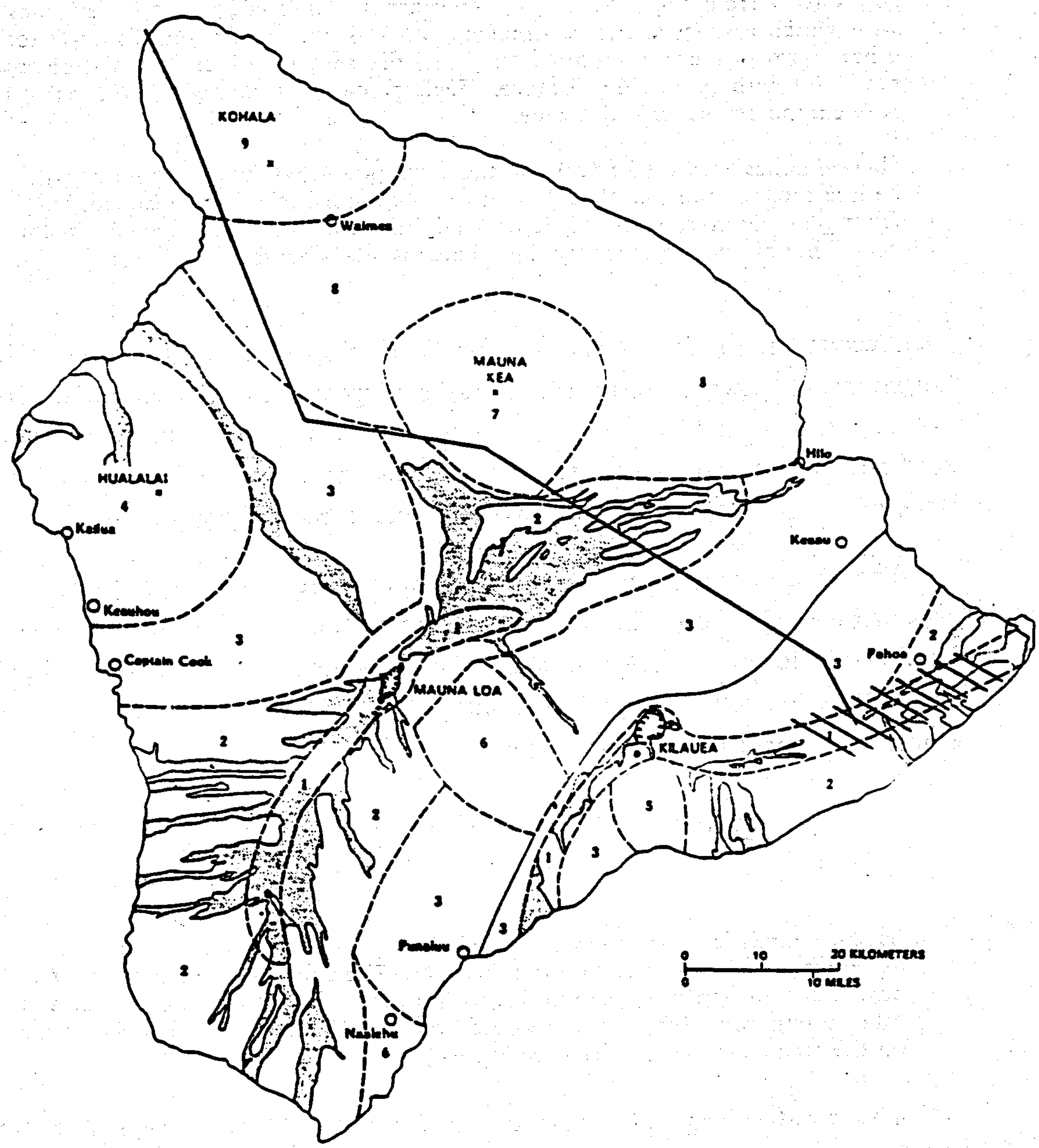
The greatest degree of hazard exists in Zone 1 and decreases as the zone number increases. Zones 1 and 2 are the zones of greatest concern.

---

1/ Conversation with Dr. Richard Moore on April 8, 1987.

## Figure 8

## HAZARD ZONES FOR LAVA FLOW ON THE ISLAND OF HAWAII




\\\\ Area of proposed geothermal development

— Proposed transmission route

po
Source: Volcanism In Hawaii, U.S. Geological Survey Professional Paper 1350.

Figure 8 indicates that the geothermal plants will be located in or near Hazard Zone 1, while the transmission lines will traverse Hazard Zone 2. Lava flow hazard zones are described as:

> "Zone 1 consists of the summit areas and active parts of the rift zones of Kilauea and Mauna Loa; in those areas, 25% or more of the land surface has been covered by lava within historical time, during the 19th and 20th centuries. These areas contain the sites of most historical eruptions, and a large majority of the lava flows that will affect other zones on Kilauea and Mauna Loa in the near future probably will originate in Zone 1.
>
> Zone 2 consists of several areas that are adjacent to and downslope from the active rift zones of Kilauea and Mauna Loa and therefore are subject to burial by lava flows of even small volume erupted in those rift zones. On Kilauea south of its east rift zone, as much as 25% of the land surface has been covered by lava during historical time, and 10-15% has been covered since 1950. Lava flows have covered parts of this area as recently as January 1986, and the history of Kilauea suggests that they will continue until some significant change occurs within the volcano. Although very little of the area in Zone 2 north of the lower east rift zone of Kilauea has been affected by lava since 1950, about 15% of that surface has been covered during historical time. On Mauna Loa, long and voluminous lava flows have repeatedly entered the areas included in Zone 2, covering about 5% of those areas since 1950 and about 20% within historical time."

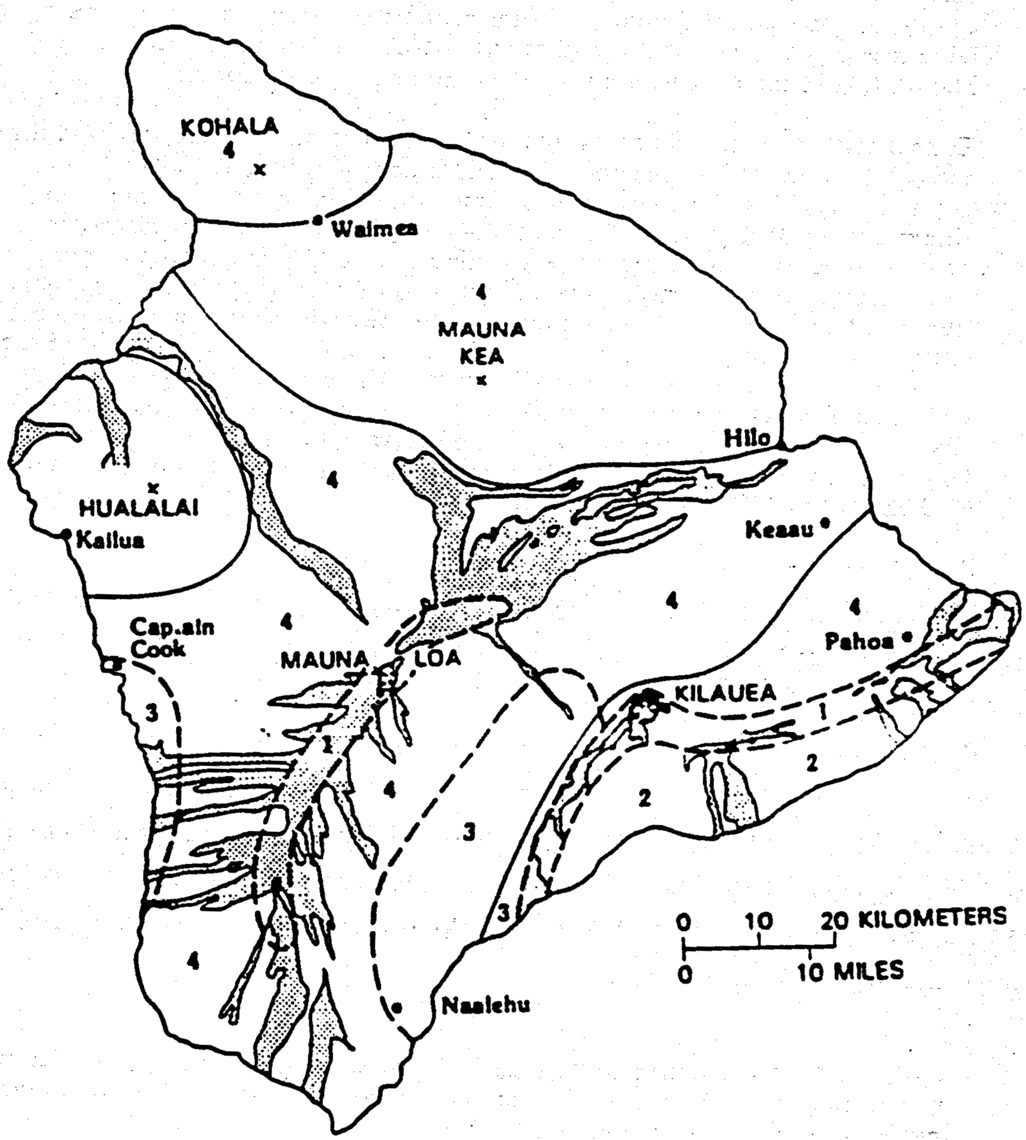
In addition to lava flows, ground fractures and subsidence will also place power plant structures at risk, especially in the Kilauea rift zone area. Figure 9 is the hazard zone map for ground fractures and subsidence. The zone of highest hazard, Zone 1, includes the summit areas and rift zones of Mauna Loa and Kilauea, where fracture and subsidence occur most frequently. On Kilauea, the geothermal plants will be located in or near this zone. Zone 2 consists of the south flank of Kilauea, where fracturing and subsidence occur somewhat less frequently than in the summit and rift zone areas. Again, from the previously cited U.S.G.S. report, the danger is apparent:

> "Large parts of the flanks of Kilauea and Mauna Loa, for example, sometimes subside abruptly. The areas affected may be several tens of kilometers long and involve hundreds of square kilometers of land."

The extent of the danger these hazards present to the project can be considerable especially over the long term. The U.S.G.S. report estimates that

Figure 9

HAZARD ZONES FOR GROUND FRACTURES AND SUBSIDENCE ON THE ISLAND OF HAWAII




Source: Volcanism In Hawaii, U.S. Geological Survey Professional Paper 1350.

about 5-10% of Kilauea and Mauna Loa could be covered with lava during any 50 year period. If 10 to 20 geothermal plants are located along Kilauea's rift zone, it does not seem unreasonable to assume that one or more may be affected by either lava flows or ground subsidence over a 40-year period. Mitigation procedures such as lava flow diversions, channels, or barriers may be temporarily effective in some cases but can create legal and social problems if the flows are diverted to an area which otherwise would have been spared. These structures would have to be quite large since lava flows can easily be more than 10 to 20 feet thick and they most likely would have to be earthen structures capable of withstanding the tremendous heat and pressure of large lava flows. Building on high ground can also be effective temporarily, but since lava flows move in unusual ways and change the elevation of the land, what was safe in one year may not be safe the next. The unusual movements of lava flows are described in the previously cited U.S.G.S. report:

> "The paths followed by lava flows are generally downslope, but they may vary in detail. Because parts of a flow are continually cooling and becoming more viscous, the flow may not move directly into the lowest available ground as would a stream of water. Lava flows may move diagonally down slopes or even cross low ridges."

A proposal to design parts of the plant for mobility and to move them about when danger is imminent will require specialized designs, moving equipment and assumes enough warning time to shut the plant down, disassemble it, and move the components to a safe place. The result is still the loss of a plant site and generating capacity. The State report assumes that destroyed plants will be rebuilt immediately, but this will depend on the magnitude and length of the eruption and assumes a replacement site and wellfield is readily available. If this assumption is wrong any components saved from destruction could not be used until new wells had been drilled and a safe wellfield and plant site located and developed.

Whatever shape the mitigation structures take their cost will be considerable and will have to be added to the plant/wellfield site development costs. None of these special design features are considered in the State report or are adequately considered in this updated NEA report.

The best advice for building in these hazardous areas comes from the U.S.G.S. report:

> "Protection from the effects of lava flows, other than by such methods of diversion or control, is generally not feasible. An individual lava flow will have roughly the same effects all the way from its source to its terminus, and attempts to protect buildings and other structures from the hot, crushing lava generally are not effective."
>
> "Avoidance through land-use zoning and evacuation is virtually the only way to reduce losses from lava flows."

The inability to control these hazards has led the U.S.G.S. to recommend that facilities that have unusual value or are essential to public health and safety should not be built in areas where hazards are high. Power plants are not only essential to the public health and safety of a community, but they provide the lifeblood required for the maintenance of a healthy, productive society. It seems unwise to locate them in areas where their functioning is likely, at best, to be disrupted or, at worst, to be completely destroyed.

## NEA - PROJECT INTEREST RATES

The cost comparison and present value analysis is done in constant dollars using "real" rates of interest. The objective of expressing costs in constant dollars is to remove the effects of inflation over time and to allow a comparison of costs using a common point as a reference. The term "real" when referring to interest rates means the rate is net of (without) inflation.

The analysis assumes the entity proposing to develop the geothermal resource will sell bonds to pay for it. To be consistent with the DAHI report, 24 year corporate utility bonds are used in the analysis although according to some experts 24 years is too long a period for a venture such as this.[1]

Four different interest rates are used in the analysis, 1) a low risk bond rate for the construction of new oil or solar/oil generating facilities, 2) a high risk bond rate for the construction of geothermal generating facilities, 3) a long-term U.S. Treasury bond rate to provide a next best alternative investment and to act as a basis for comparing the present net values of the three power generation alternatives, and 4) a short-term U.S. Government security rate for the highly liquid plant replacement insurance fund.

The interest rates used in the analysis can be found in Table 12. The 10 year average real rate is used in the analysis Aaa Public Utility bond rate was selected for oil and solar/oil alternatives. This rate assumes the risk for the investor is low and therefore the cost to the entity issuing the bond is also low. Bond insurance increases the rate by 0.0025.

The Baa bond rate is used for geothermal investment. The Baa bond is a higher risk bond. Since the geothermal venture is higher in risk than the other alternatives a higher return will have to be guaranteed to investors for their participation. A higher return to the investor means a higher cost to the issuing entity. Bond insurance is high risk as well and increases the rate by 0.01.

1/ Alex Sifford, Geothermal Program Manager, Oregon Department of Energy, in his review of the DAHI report, June, 1988.

## Table 12

## INTEREST RATES 1/

| Year | Public Utility Bonds Aaa | Public Utility Bonds Aaa | Public Utility Bonds Baa | Public Utility Bonds Baa | Bond Risk Factor | U.S. Treasury Bonds Earning Rate | U.S. Treasury Bonds Earning Rate | U.S. Govnmt Securities Earning Rate | U.S. Govnmt Securities Earning Rate | Annual Inflation Rate |
|---|---|---|---|---|---|---|---|---|---|---|
| | Nominal | Real | Nominal | Real | | Nominal | Real | Nominal | Real | Real |
| 1974 | 8.71 | 2.81 | 9.84 | 3.94 | 1.13 | 6.98 | 1.08 | 7.94 | 2.04 | 5.90 |
| 1975 | 9.03 | -0.27 | 10.96 | 1.66 | 1.93 | 6.98 | -2.32 | 6.09 | -3.21 | 9.30 |
| 1976 | 8.63 | 2.23 | 9.82 | 3.42 | 1.19 | 6.78 | 0.38 | 5.25 | -1.15 | 6.40 |
| 1977 | 8.19 | 1.49 | 9.06 | 2.36 | 0.87 | 7.06 | 0.36 | 5.53 | -1.17 | 6.70 |
| 1978 | 8.87 | 1.57 | 9.62 | 2.32 | 0.75 | 7.89 | 0.59 | 7.58 | 0.28 | 7.30 |
| 1979 | 9.86 | 0.96 | 10.96 | 2.06 | 1.10 | 8.74 | -0.16 | 10.06 | 1.16 | 8.90 |
| 1980 | 12.30 | 3.30 | 13.95 | 4.95 | 1.65 | 10.81 | 1.81 | 11.37 | 2.37 | 9.00 |
| 1981 | 14.64 | 4.94 | 16.60 | 6.90 | 1.96 | 12.87 | 3.17 | 13.80 | 4.10 | 9.70 |
| 1982 | 14.22 | 7.82 | 16.45 | 10.05 | 2.23 | 12.23 | 5.83 | 11.07 | 4.67 | 6.40 |
| 1983 | 12.52 | 8.62 | 14.20 | 10.30 | 1.68 | 10.84 | 6.94 | 8.73 | 4.83 | 3.90 |
| 1984 | 12.72 | 9.02 | 14.53 | 10.83 | 1.81 | 11.99 | 8.29 | 9.76 | 6.06 | 3.70 |
| 1985 | 11.68 | 8.68 | 12.96 | 9.96 | 1.28 | 10.75 | 7.75 | 7.65 | 4.65 | 3.00 |
| 1986 | 8.92 | 6.22 | 10.00 | 7.30 | 1.08 | 8.14 | 5.44 | 6.03 | 3.33 | 2.70 |
| 1987 | 9.52 | 6.22 | 10.53 | 7.23 | 1.01 | 8.63 | 5.33 | 6.03 | 2.73 | 3.30 |
| 1988 | 10.05 | 6.95 | 11.00 | 7.90 | 0.95 | 8.98 | 5.88 | 6.09 | 2.99 | 3.10 |
| 5 yr. avg. | 10.58 | 7.42 | 11.80 | 8.64 | 1.23 | 9.70 | 6.54 | 7.11 | 3.95 | 3.16 |
| 10 yr. avg. | 11.64 | 6.27 | 13.12 | 7.75 | 1.47 | 10.40 | 5.03 | 9.06 | 3.69 | 5.37 |
| 15 yr. avg. | 10.66 | 4.70 | 12.03 | 6.08 | 1.37 | 9.31 | 3.36 | 8.20 | 2.25 | 5.95 |

1/ "Moody's Public Utility Manual," Moody's Investors Service, 1989; and U.S. Statistical Abstract.

The U.S. Treasury bond rate is used as a discount rate to compare the present values of the total 40 year costs of the three alternatives.

The short-term U.S. Government security rate (six month treasury bills) is used as the rate at which the plant replacement fund earns interest since the funds must be liquid and accessed quickly if needed.

## NEA - PROJECT INSURANCE RATES

Determining the cost of insuring the geothermal project is difficult since the hazards present a unique situation, and while anything is insurable the question is at what cost? The two most likely causes of damage to the power plants and well fields are lava flows and ground subsidence, while sea-floor earthquakes would be the most likely cause of damage to the undersea cable. (See NEA - Geothermal Project Hazard Assessment section.)

To get an idea of what it would cost to insure the power plants and their facilities, commercial insurance representatives[1] were contacted at the Fred S. James Company, an insurance bookerage firm in Seattle and Los Angeles. They said that perhaps Lloyds of London or AIG would be the type of company that could handle a venture as large as the geothermal project but, without much more information on the specifics of the project (i.e. hazard frequency and intensity, plant location, plant construction details, specific in-place mitigation procedures), no accurate estimate of project insurance cost could be made or even attempted. They did indicate however, that the cost of the insurance would be quite high if it was available at all. None of the representatives was aware of anyone currently offering insurance against the specific types of hazards described (lava flows, ground subsidence, etc.).

There is, however, some parallel between lava flow hazard and floodplain hazard. In both cases damage is caused by a moving liquid material, but while flood damage need not be total, lava flow damage most assuredly is.

To explore this option the Federal Emergency Management Agency (FEMA) in San Francisco was contacted.[2] While FEMA does not insure against lava flows (and is not aware of anyone who does), it does issue flood plain insurance up to a value of $200,000 per structure. The rates vary depending on

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1/ Phone conversation with Craig Brandt, Fred S. James Company, Seattle, WA January - February, 1989.

2/ Phone conversation with John Eldridge, Federal Emergency Management Agency, San Francisco, California, February, 1989.

flood frequency, intensity and the location of the structure in relation to the maximum height of the flood waters. Some rates for worst case flood scenarios are shows in Table 13).

**Table 13**

**FLOOD INSURANCE RATES**
**100 YR FLOOD**

| Annual Rate $100 Value | Location of Floor Level Below Maximum Height Of Floodwater |
|---|---|
| $2.65 | 5 feet |
| $3.85 | 6 feet |
| $5.30 | 7 feet |

The highest rate quoted was $6.60 per $100 value for structures at the lowest level below maximum floodwater, while the lowest rate was 12¢ per $100 value if the lowest level of the structure was built three feet above the maximum height of the floodwater.

Since lava flows are much more destructive than floodwaters and can easily reach thicknesses of ten feet or more,[1] mitigation against them is costly and at best uncertain (see Geothermal Project Hazard Assessment section), it is likely that insurance costs to protect against them would be at least at the $6.60 total destruction level for a 100 year frequency event.

If this rate ($6.60 per $100 value) is applied to the entire value of a 25 MW power plant whose replacement cost is between $100 million and $130 million (our low and high plant/well field development costs as generated in the CENTPLANT model) the annual insurance cost would be between $7.1 and $8.6 million per 25 MW plant or between $142 million and $172 million dollars for the entire project (twenty 25 MW plant/wellfield sites) at full development. At this rate the cost of insurance over the life of the project easily exceeds the cost of replacing all the plants and facilities. Clearly, this would not be the preferred option.

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1/ *Volcanism In Hawaii*, Chapter 22, U.S. Geological Survey Professional Paper 1350, 1986.

The only other option open is self-insurance, or absorbing the losses internally. If the self-insurance option were taken the project owners would have to not only make good on losses to bond holders but would have to pay for the immediate replacement of lost generating capacity. It may prove quite difficult to sell bonds to finance a new geothermal plant to be built in an area containing hazards identical to one that had just been destroyed by lava flows or ground subsidence. Bond buyers and insurers would probably be a bit more skeptical of the safety of their investment the second time around and would probably require an even higher interest rate to cover their risk than the initial offering which was a higher risk bond to begin with.

If it proved difficult to issue bonds at a reasonable rate, money would have to be available from some other source in an amount large enough to insure that the reserve capacity of the system did not remain below critical levels for a long period of time. Output from existing geothermal plants could not simply be increased to replace the lost power since the geothermal plants would already be operating at their maximum output capacity. The replacement power would have to come from somewhere else, and it would have to come quickly because maintaining adequate reserve generating capacity is critical to public safety.

If, for example, total generating capacity were 2000 MW and 30% (600 MW) were required to be held in reserve, 70% (1400 MW) would be available for the system's annual load. The reserve is there to handle peak loads and emergency demands that may occur. If some geothermal capacity were lost, reserve capacity would drop as well as shown in Table 14.

If 50 MW is lost the reserve margin drops to 28%; if 100 MW is lost it drops to 26%. If we are looking at 25 MW plants and 2 -4 plants are lost, the amount of capital needed immediately to bring the reserve capacity back up to the 30% level would be half a billion dollars. If 6 plants were lost, about three quarters of a billion dollars would be needed in a short period of time.

Table 14

| GENERATING CAPACITY AND RESERVE<br>Capacity Relationships | | | | |
|---|---|---|---|---|
| Total Capacity (MW) | 2000 | 1950 | 1900 | 1850 |
| Peak (MW) | 1400 | 1400 | 1400 | 1400 |
| Reserve Capacity (MW) | 600 | 550 | 500 | 450 |
| Reserve Margin | 30% | 28% | 26% | 24% |
| MW Loss | 0 | 50 | 100 | 150 |
| MW/Plant | 25 | 25 | 25 | 25 |
| # Plants | 0 | 2 | 4 | 6 |
| M$/Plant Low | | 107.79 | 107.79 | 107.79 |
| M$/Plant High | | 129.40 | 129.40 | 129.40 |
| M$ Total Capital Low | | 215.58 | 431.16 | 646.74 |
| M$ Total Capital High | | 258.80 | 517.60 | 776.40 |

Either insurance, self-insurance or some combination of the two will require immense sums of money and presents a formidable obstacle in terms of costs to be shouldered by ratepayers. In the analysis a worst case scenario is assumed and bonds cannot be sold to finance replacement power plants. A replacement plant fund is established beginning in year three to insure that money is available to replace one-half the power plants and one-third the cable system exposed to geologic hazards. The fund is increased accordingly as plants come on line until full development is reached in the twenty-first year. The money is then expended to replace power plants and transmission facilities lost in years 22, 30, 34 and 35. In the 25 MW scenario eight plants are lost, two in each year, while in the 50 MW scenario four plants are lost. Since the bonds initially issued are insured, remaining bond payments on each plant are eliminated as the plants are lost. In addition, the fund earns interest but since it must be reasonably liquid and cannot be tied up in long-term investments it earns interest at a rate equal to short-term U.S. Government securities (six month Treasury bills).

This risk level is based on the high level of uncertainty in predicting volcanic activity in the development area as described in the U.S.G.S. report cited in the earlier chapter on geologic hazards. The report describes the prediction of volcanic activity and lava coverage as follows:

"Based on historical records, about 5-10 percent of Kilauea and Mauna Loa could be covered during any 50-year period. Although wide fluctuations can be expected in eruptive rates from one decade to another, the overall rates likely will remain about the same. It is not possible, however, to predict where the next eruptive centers will be, how frequent or copious eruptions will be in a specific area, or which specific areas will be covered by lava.

The volcanic activity along Kilauea's east rift zone in historical time illustrates a difficulty in using the short historical record to predict future activity in a specific area. Between 1800 and 1950, approximately 2 percent of the eastern flanks of the volcano had been covered by lava from the east rift zone. In 1950, the probability based on these figures that a site in that region would be covered would have been 0.013 percent per year. However, between 1950 and 1975 about 8 percent of Kilauea's east flank was covered by lava, and so the coverage in that interval was actually about 0.32 percent per year. Estimates of future coverage may be no more accurate."

In the description cited above actual lava coverage was 25 times as extensive as would have been predicted based on historical records. Given the axiom that risk becomes greater as uncertainty becomes greater, that low probability events can and do occur, and given the nature of the hazards associated with the area of the proposed development, our assumption of a one-half plant replacement fund at the worst case scenario and a 40% plant loss does not seem unreasonable.

# NEA - THE PRICE OF RESIDUAL FUEL OIL

Determining future world oil prices is difficult because it depends greatly on the level of world oil production, future oil exploration and discovery, and market responses (demand, substitution etc.) to oil prices over the long term.

It is generally agreed, and time has shown, that the price of oil is crucial to the availability and price of all other energy. A Wall Street Journal article[1] discussing petroleum use states that while there is still concern about OPEC domination of oil resources in the future, other forces will act to keep prices in check. The article puts it this way:

> Some suggest this could set the stage for a return of the political upheavals and price escalation of the 1970s. But others say leading members of OPEC such as Saudi Arabia are convinced that relatively low oil prices are in their best interests in the long term. They don't want to spur oil exploration in other areas–in the high-cost U.S., for example, where production has rapidly declined since the 1986 crash–or lose customers to alternate energy sources likely to be launched on the next petroleum price spike.
>
> But relatively low oil prices will discourage investment in research and development of alternate energy sources. That's because many potential alternatives, which might be competitive with $40 to $50 a barrel oil, can't compete on a cost basis with $18 a barrel oil.
>
> "In the short run, cheap oil keeps down natural gas and coal," says Robert H. Horton, a managing director of British Petroleum Co. "In the longer run, these and others–including our exotic old friends like solar, shale, windmills and the atom– curb excess greed on the part of oil."

The Gas Research Institute[2] agrees on the effects high oil prices have on other energy sources:

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1/ The Wall Street Journal Industry Focus, *Petroleum Use To Maintain Its Stature*, March 1, 1989.

2/ The Gas Research Institute, *'89 Policy Implications Of The GRI Baseline Projection Of U.S. Energy Supply And Demand To 2010.*

"GRI's oil price projections have been changed over time in response to new information as the historical years have been added. In retrospect, two major factors have continually been underestimated:

- On the supply side, the response of new non-OPEC supplies to high prices in the 1970s and the persistence of that supposedly high-cost production in the face of the more recent low price periods; and
- On the demand side, the dramatic reduction in the use of residual fuel oil in stationary energy applications, which was aided in the 1980s by a period of low energy demand growth (conservation) coupled with over investment in new nuclear and coal-fired electric power generating capacity."

While oil prices may increase from time to time, it is not likely they will increase beyond the point at which other energy sources become available and competitive. Based on the experience of the 1970s, that point seems to be in the range of $40 to $50 per barrel.

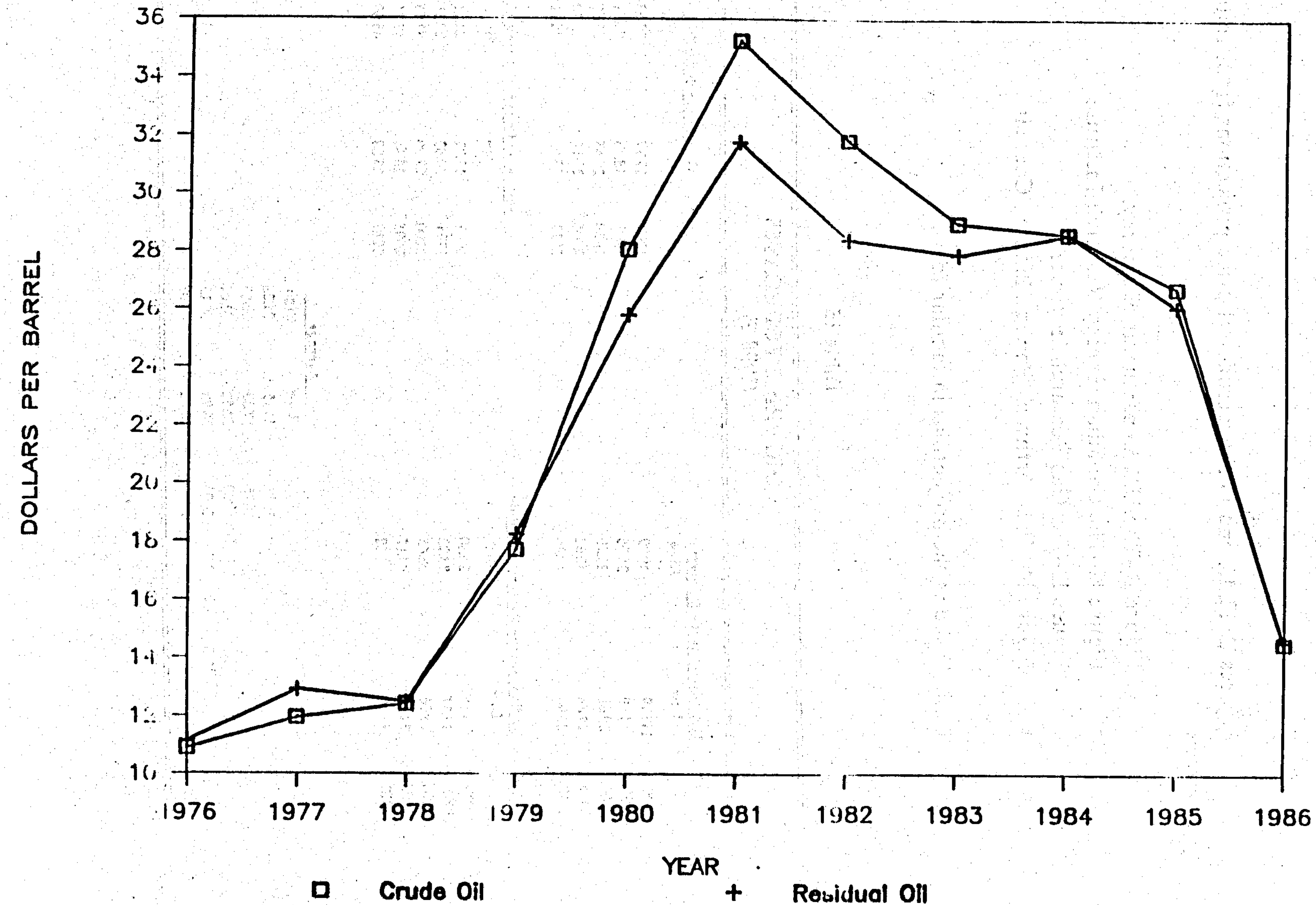
The same Wall Street Journal article mentioned above goes on to state:

> Petroleum prices today average between $14 and $18 a barrel, half the level of the early 1980s. The future direction is subject to debate, not surprisingly since a former consensus forecast of $80 oil by now was off the mark. Generally, prices are expected to remain somewhat flat for a few years and then rise gradually.
>
> Many agree with the Petroleum Industry Research Foundation's energy economists who see prices averaging between $15 and $20 a barrel, in real terms, through the 1990s. "We don't see a $25 or $40 world nor a $10 world, but we could still have violent swings," says Lawrence Goldstein, the foundation's executive vice president.

The type of fuel oil used in the plants in the analysis is residual fuel oil. This is the heavier oil that remains after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery generation. Since the price of residual fuel oil and crude oil are very close on the world market (Figure 10), the report assumes they are equivalent.

Figure 10

## CRUDE OIL AND RESIDUAL OIL PRICES



Figures 11, 12, 13, and 14 show crude oil price projections from four different sources:

- Figure 11–The U.S. Department of Energy.
- Figure 12–The Canadian Energy Research Institute
- Figure 13–The Gas Research Institute
- Figure 14–The Northwest Power Planning Council

Table 15 shows the projections in tabular form.

Table 15

**OIL PRICE FORECASTS**
**(1990 $)**

| | U.S. Department of Energy | | Gas Research Institute | |
|---|---|---|---|---|
| | Low | High | Low | High |
| 1990 | 143.99 | 19.99 | 17.37 | 20.63 |
| 1995 | 14.89 | 26.96 | 18.46 | 21.71 |
| 2000 | 20.61 | 35.29 | 20.63 | 23.88 |
| 2005 | 24.88 | 43.62 | 27.14 | 30.40 |
| 2010 | 26.96 | 49.34 | 33.65 | 36.91 |

| | Canadian Energy Research Institute | | Northwest Power Planning Council | |
|---|---|---|---|---|
| | Low | High | Low | High |
| 1990 | 10.86 | 22.80 | 17.37 | 21.71 |
| 1995 | 17.37 | 28.23 | 20.63 | 29.31 |
| 2000 | 26.06 | 33.65 | 22.80 | 33.65 |
| 2005 | 32.57 | 40.17 | 23.34 | 42.34 |
| 2010 | 38.00 | 46.68 | 23.88 | 45.60 |

| | Average | |
|---|---|---|
| | Low | High |
| 1990 | 15.15 | 21.28 |
| 1995 | 17.83 | 26.55 |
| 2000 | 22.52 | 31.62 |
| 2005 | 26.98 | 39.13 |
| 2010 | 30.62 | 44.63 |

Figure 11

# OIL PRICE FORECAST

U.S.DEPARTMENT OF ENERGY

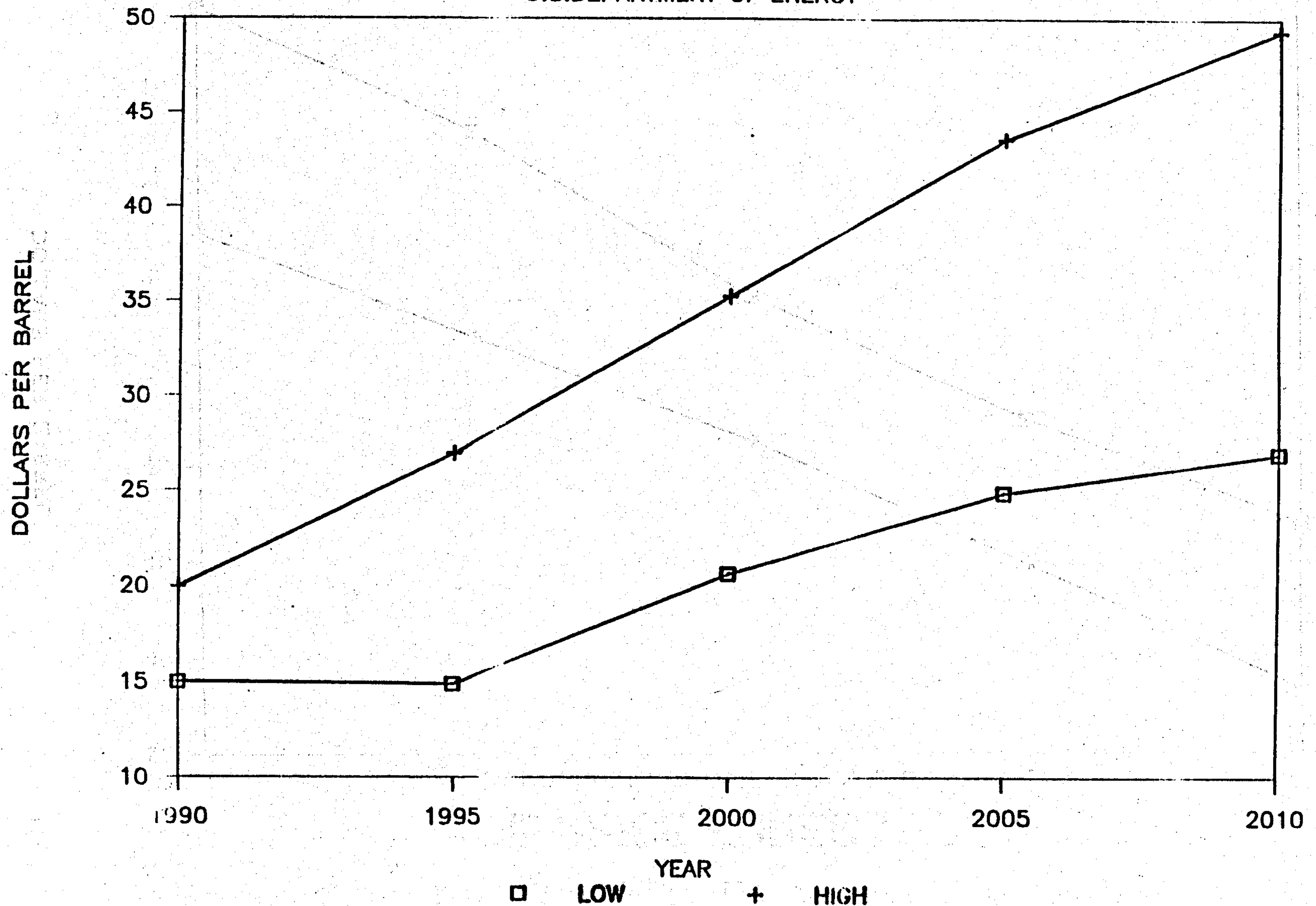


Figure 12

**OIL PRICE FORECAST**

CANADIAN ENERGY RESEARCH INSTITUTE

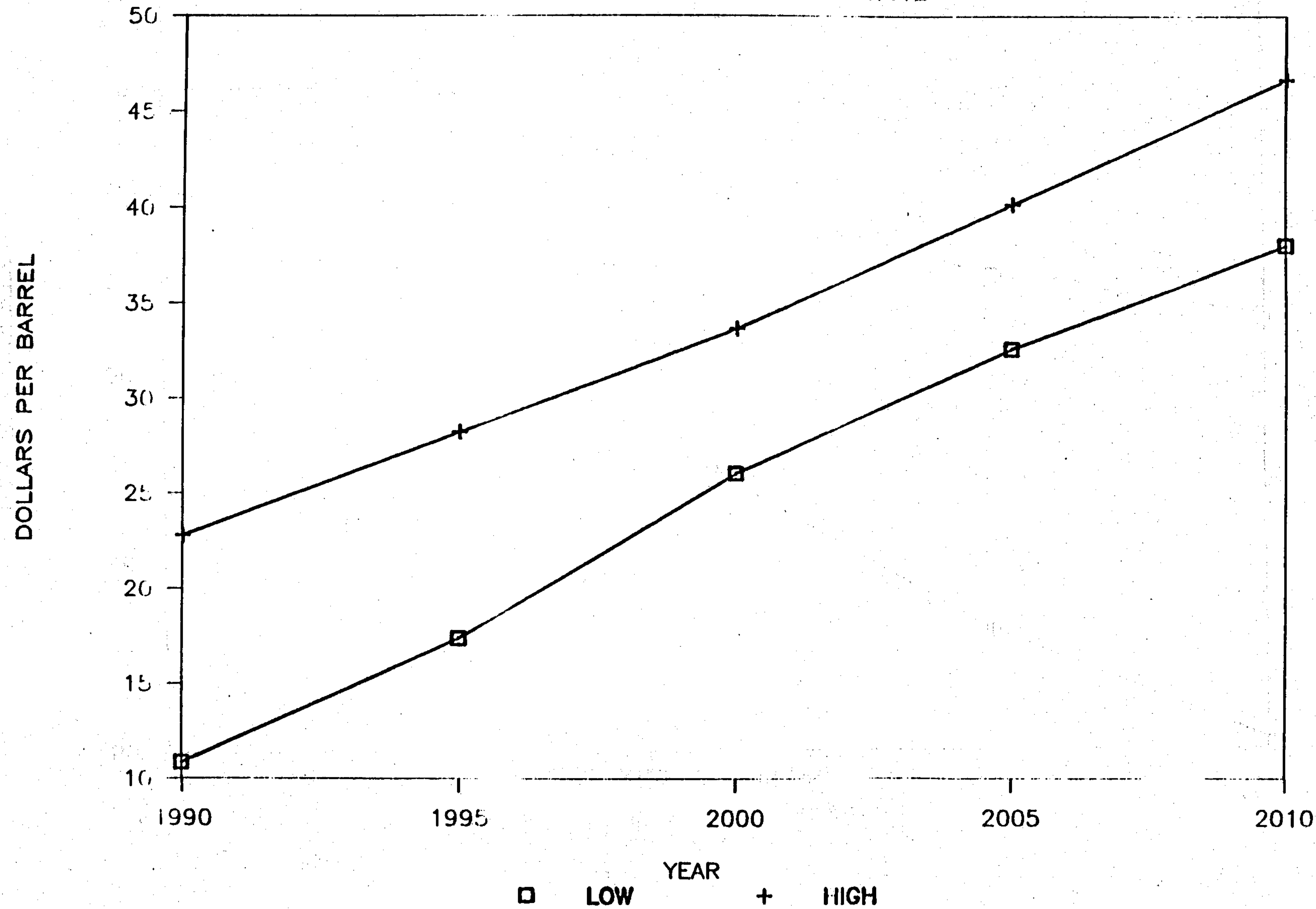


Figure 13

## OIL PRICE FORECAST

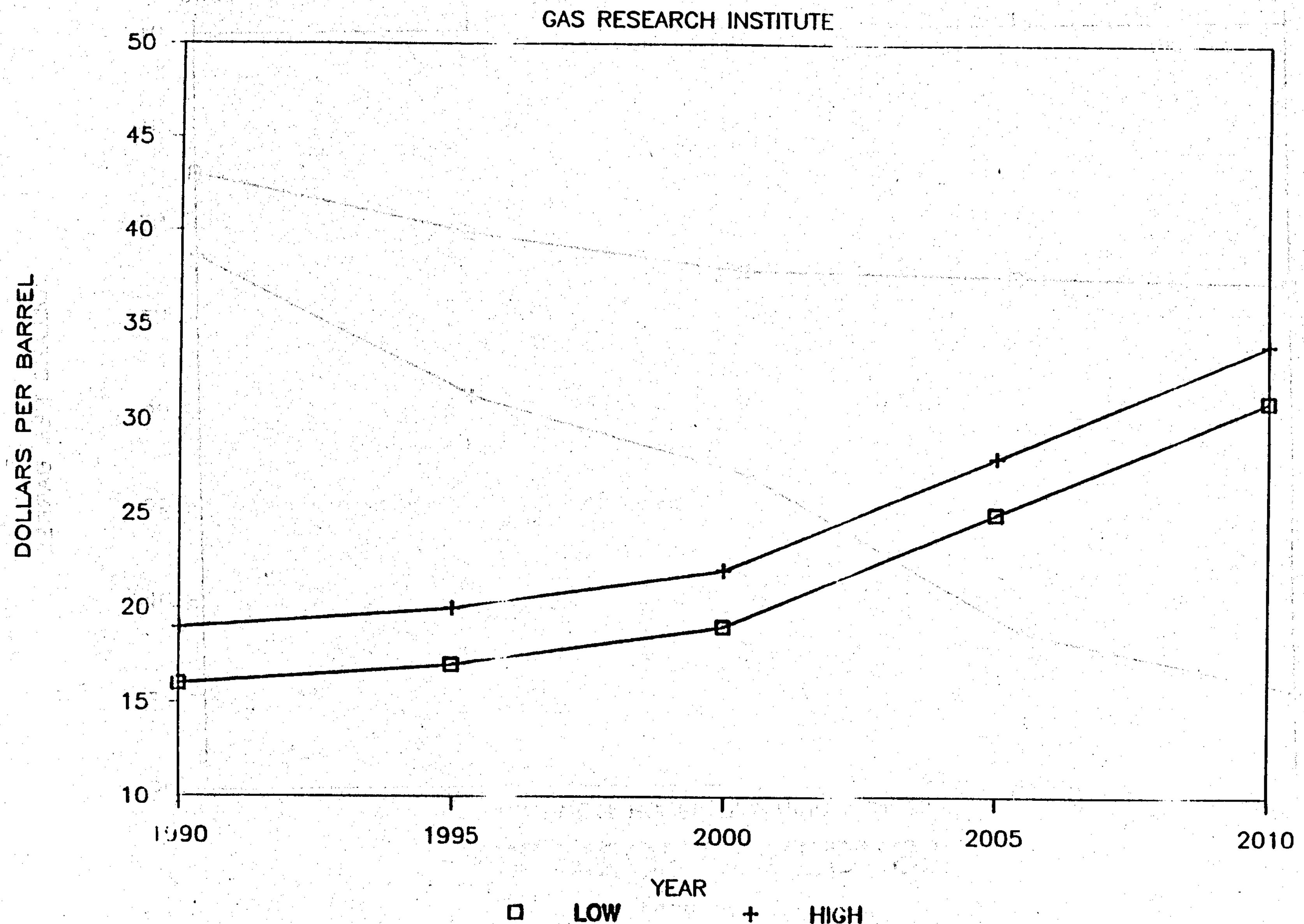
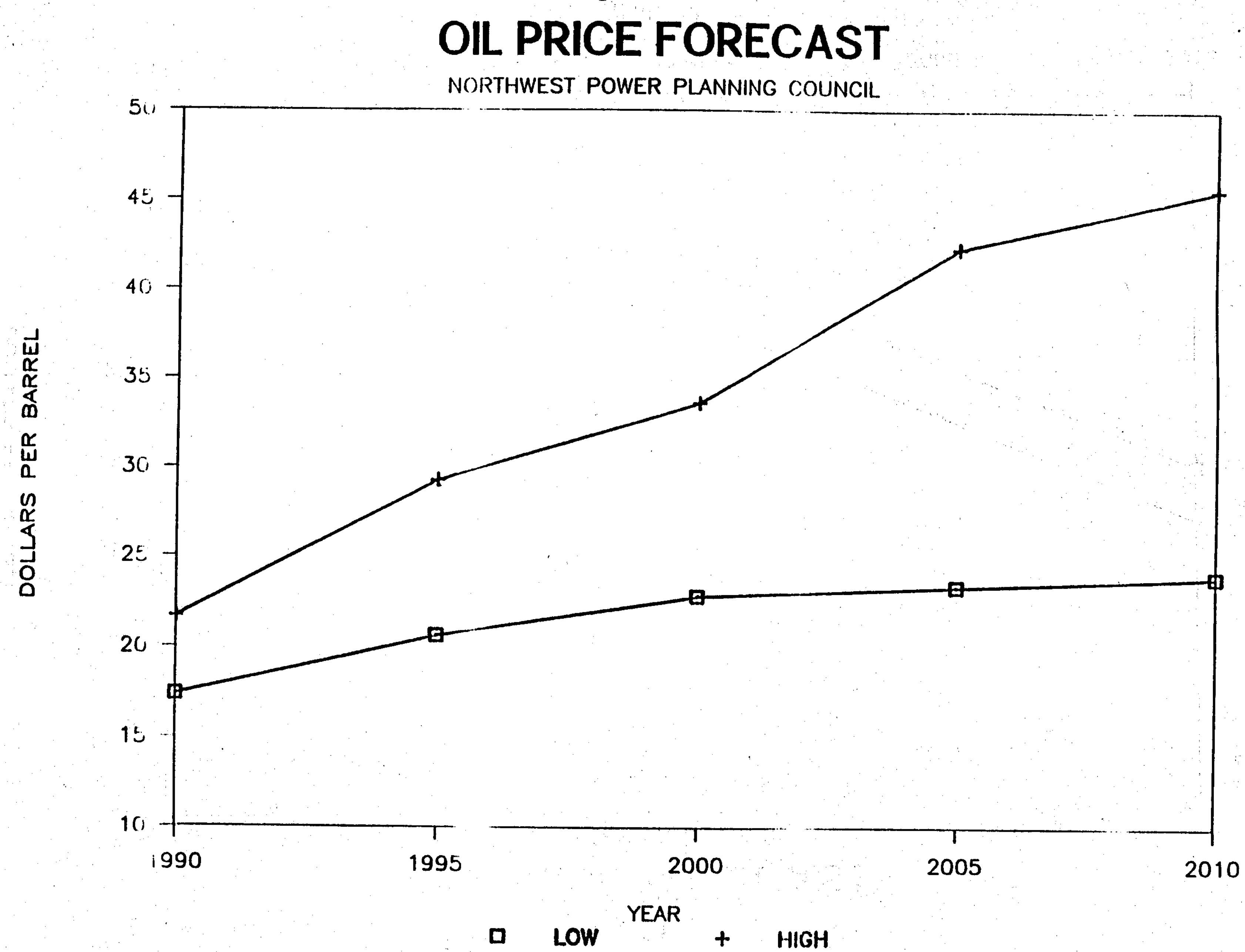


Figure 14



OIL PRICE FORECAST
NORTHWEST POWER PLANNING COUNCIL
DOLLARS PER BARREL
50
45
40
35
30
25
20
15
10
1990
1995
2000
2005
2010
YEAR
LOW
HIGH

The highest high price projection is from the U.S. Department of Energy at $49.34 per barrel in 2010. The lowest low price if from the Northwest Power Planning Council at $23.88 per barrel in 2010. The average of the four sets of projections is $30.62 on the low end and $44.63 on the high end in 2010.

The oil prices used in the analysis are based on these oil price projections and on the belief that market forces will limit oil prices to below $50 per barrel. An oil price of $25 per barrel is used as a starting point in the 5th year (1994) and is increased at an annual real rate of 4.0% until a price of $45.00 is reached in the 21st year (2010). The $45.00 price is then kept constant throughout the remainder of the analysis period. The oil price is in 1990 dollars.

# NEA - PROJECT COST COMPARISON

In this analysis the cost of generating 500 net MW of electricity from the three different sources described earlier is compared:

Generation sources:

Alternative #1
20 - 25 net MW geothermal power plants

Alternative #2
5 - 100 net MW oil-fired power plants

Alternative #3
5 - 100 net MW solar/oil-fired power plants

Alternatives 2 and 3 are also compared to ten 50 net MW geothermal power plants.

The following four scenarios detail the costs of the three generating options used in the analysis. Scenario 1 uses 25 MW power plants at the low plant cost; Scenario 2 uses 25 MW power plants at the high plant cost; Scenario 3 uses 50 MW power plants at the low plant costs; and Scenario 4 uses 50 MW power plants at the high plant costs.

Capital costs used are described in earlier project cost sections. Interest rates, insurance, and oil prices are also described in earlier sections. Other costs used in the analysis are explained below. The project spans a 40 year time period. All dollar amounts are in 1990 dollars.

The major line items in the scenarios are explained as follows:

| | |
|---|---|
| Scenario - | describes the scenario being compared. |
| Year - | is the year of the project. |

## GEOTHERMAL POWER GENERATION

| | |
|---|---|
| Geothermal Development Timetable (MW) | Is the phasing in of geothermal plants. For 25 MW plants one is brought on line every 12 months. For 50 MW plants one is brought on line every 24 months. 500 MW is on line by the end of the 21st year. |

## GEOTHERMAL POWER GENERATION cont'd

| | |
|---|---|
| Electricity Produced | Is the amount of electricity produced in 1000 MWh assuming the plants operate at 80% capacity (80% of the time). |
| Geothermal Plants (M$) | Costs of the plants shown in million dollars |
| Capital | The annual capital costs of the power plants using Baa bond rates. See section NEA - Project Interest Rates. |
| Replacement Wells | The annual cost to replace or rework production wells. |
| O&M | The annual O&M costs of the power plants. (CENTPLANT Generated.) |
| Royalty | An assessment made by the state on geothermal power production. We assumed an assessment of 10% on gross power sales after the 8th year of production. |
| Rent | Rent paid to the state in the amount of 4% of gross power sales. |
| Plant Replacement Fund | Is the fund set aside in lieu of insurance to replace power plants lost to geologic hazards. |
| Cable and Facilities (M$) | |
| Capital | The annual capital costs of the overland and undersea cable systems using Baa bond rates. |
| O&M | The estimated annual O&M costs of the cable systems. (NEA estimate.) |
| Administrative Expenses | Based on administrative costs per kWh found in Hawaiian Electric Industries, Inc. Annual Report. |
| Cost | Total annual project costs. |
| With Profit | Total annual project costs with 8% profit calculated from Hawaiian Electric Industries, Inc. Annual Report. Profit is calculated as a percent of annual costs. |

The second set of costs is in cents per kilowatt hour.

## RESIDUAL FUEL OIL POWER GENERATION

| | |
|---|---|
| Oil Facility Development Timetable (MW) | Is the phasing in of oil fired power plants. One 100 MW plant is brought on line every 5 years. 500 MW is on line by the end of the 21st year. |
| Oil Price | Is the price paid for a barrel of residual fuel oil. See section NEA - The Price of Residual Fuel Oil. |

## RESIDUAL FUEL OIL POWER GENERATION cont'd

| | |
|---|---|
| Electricity Produced | Is the amount of electricity produced in 1000 MWh assuming the plants operate at 80% capacity (80% of the time). |
| Oil Consumed | The amount of oil in million barrels it takes to produce the electricity in the line just above. We used a fuel conversion efficiency factor of 35%. |
| Capital | The annual capital costs of the power plants using Aaa bond rates. |
| O&M | The annual O&M costs of the power plants. (Northwest Power Planning Council estimate.) |
| Fuel | The annual fuel costs of the power plants (oil consumed times oil price). |
| Administrative Expenses | Based on similar costs per kWh found in Hawaiian Electric Industries, Inc. Annual Report. |
| Cost | Total annual project cost. |
| With Profit | Total annual project cost with 8% profit. Profit is calculated as a percent of annual costs based on Hawaiian Electric Industries, Inc. Annual Report. |

The second set of costs is in cents per kilowatt hour.

## SOLAR/RESIDUAL FUEL OIL POWER GENERATION

| | |
|---|---|
| Solar Facility Development Timetable (MW) | Is the phasing in of oil fired power plants. One 100 MW plants is brought on line every 5 years. 500 MW is on line by the end of the 21st year. |
| Electricity Produced | Is the amount of electricity produced in 1000 MWh assuming the plants operate at 80% capacity (80% of the time). |
| Solar Produced Electricity | Is the amount of electricity produced in 1000 MWh by the solar generation portion of the facility. |
| Oil Price | Is the price paid for a barrel of residual fuel oil. See section NEA - The Price of Residual Fuel Oil |
| Oil Produced Electricity | Is the amount of electricity produced in 1000 MWh by the oil generation portion of the facility. |
| Oil Consumed | The amount of oil in million barrels it takes to produce the electricity in the line just above. We used a fuel conversion efficiency factor of 35%. |
| Capital | The annual capital costs of the power plants using Aaa bond rates. |

[illegible]

## SCENARIO 1

25 MW power plants using
low plant/wellfield costs and a
20% contingency

SCENARIO #1: 25 MW GEOTHERMAL PLANTS, LOW PLANT COSTS, FUEL OIL PRICE STABILIZES AT $45.00 PER BARREL IN 21ST YEAR OF PROJECT

| GEOTHERMAL POWER GENERATION YEAR | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Geothermal Development Timetable(MW) | | | 50 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| Total Net Capacity Development | | | 50 | 75 | 100 | 125 | 150 | 175 | 200 | 225 | 250 | 275 | 300 | 325 | 350 | 375 | 400 | 425 | 450 | 475 | 500 |
| Electricity Produced (1000MWh) | | | 350 | 526 | 701 | 876 | 1051 | 1226 | 1402 | 1577 | 1752 | 1927 | 2102 | 2278 | 2453 | 2628 | 2803 | 2978 | 3154 | 3329 | 3504 |
| COST FOR GEOTHERMAL POWER PROJECT | | | | | | | | | | | | | | | | | | | | | |
| Geothermal Plants (M$) | | | | | | | | | | | | | | | | | | | | | |
| Capital | 21.8 | 21.8 | 43.5 | 43.5 | 65.3 | 65.3 | 87.1 | 87.1 | 108.8 | 108.8 | 130.6 | 130.6 | 152.4 | 152.4 | 174.1 | 174.1 | 195.9 | 195.9 | 217.7 | 217.7 | 217.7 |
| Replacement Wells | | | | | 4.1 | 4.1 | 8.1 | 8.1 | 12.2 | 12.2 | 16.2 | 16.2 | 20.3 | 20.3 | 24.3 | 24.3 | 28.4 | 28.4 | 32.4 | 32.4 | 36.5 |
| O&M | | | 5.6 | 8.4 | 11.2 | 14.0 | 16.7 | 19.5 | 22.3 | 25.1 | 27.9 | 30.7 | 33.5 | 36.3 | 39.1 | 41.9 | 44.6 | 47.4 | 50.2 | 53.0 | 55.8 |
| Royalty Payments | | | | | | | | | | | 12.6 | 14.2 | 15.5 | 17.3 | 19.1 | 21.1 | 22.9 | 25.0 | 27.3 | 29.7 | 30.2 |
| Rent | 1.0 | 1.0 | 1.0 | 1.4 | 1.9 | 2.4 | 3.0 | 3.6 | 3.8 | 4.4 | 5.0 | 5.7 | 6.2 | 6.9 | 7.7 | 8.4 | 9.2 | 10.0 | 10.9 | 11.9 | 12.1 |
| Plant Replacement Fund | | | 135.2 | 0.0 | 119.7 | 0.0 | 114.9 | 0.0 | 104.7 | 0.0 | 94.6 | 0.0 | 84.4 | 0.0 | 74.2 | 0.0 | 64.1 | 0.0 | 53.9 | 0.0 | 43.8 |
| Cables and Facilities (M$) | | | | | | | | | | | | | | | | | | | | | |
| Capital | 40.3 | 40.3 | 40.3 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 |
| O&M | | | 1.0 | 1.0 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Administrative Expenses (M$) | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 |
| Cost (M$) | 63.1 | 63.1 | 226.7 | 122.4 | 271.7 | 155.4 | 299.5 | 188.0 | 321.6 | 220.3 | 356.7 | 267.3 | 382.1 | 303.0 | 408.5 | 339.8 | 435.0 | 376.8 | 462.5 | 414.8 | 466.0 |
| With profit (M$) | 68.4 | 68.4 | 245.8 | 132.8 | 294.7 | 168.5 | 324.8 | 203.9 | 348.8 | 238.9 | 386.9 | 289.9 | 414.4 | 328.6 | 443.0 | 368.5 | 471.8 | 408.6 | 501.6 | 449.9 | 505.4 |
| Cents/KWh (geothermal) | | | | | | | | | | | | | | | | | | | | | |
| Geothermal Plants | | | | | | | | | | | | | | | | | | | | | |
| Capital | 6.21 | 6.21 | 12.42 | 8.28 | 9.32 | 7.45 | 8.28 | 7.10 | 7.77 | 6.90 | 7.45 | 6.78 | 7.25 | 6.69 | 7.10 | 6.63 | 6.99 | 6.58 | 6.90 | 6.54 | 6.21 |
| Replacement Wells | | | | | 0.58 | 0.46 | 0.77 | 0.66 | 0.87 | 0.77 | 0.92 | 0.84 | 0.96 | 0.89 | 0.99 | 0.92 | 1.01 | 0.95 | 1.03 | 0.97 | 1.04 |
| O&M | | | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 |
| Royalty Payments | | | | | | | | | | | 0.72 | 0.74 | 0.74 | 0.76 | 0.78 | 0.80 | 0.82 | 0.84 | 0.87 | 0.89 | 0.86 |
| Rent | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.28 | 0.29 | 0.29 | 0.27 | 0.28 | 0.29 | 0.30 | 0.29 | 0.30 | 0.31 | 0.32 | 0.33 | 0.34 | 0.35 | 0.36 | 0.34 |
| Plant Replacement Fund | | 0.00 | 38.59 | 0.00 | 17.08 | 0.00 | 10.93 | 0.00 | 7.47 | 0.00 | 5.40 | 0.00 | 4.01 | 0.00 | 3.03 | 0.00 | 2.29 | 0.00 | 1.71 | 0.00 | 1.25 |
| Cables and Facilities | | | | | | | | | | | | | | | | | | | | | |
| Capital | 11.50 | 11.50 | 11.50 | 12.94 | 9.70 | 7.76 | 6.47 | 5.55 | 4.85 | 4.31 | 3.88 | 3.53 | 3.23 | 2.99 | 2.77 | 2.59 | 2.43 | 2.28 | 2.16 | 2.04 | 1.94 |
| O&M | | | 0.29 | 0.19 | 0.21 | 0.17 | 0.14 | 0.12 | 0.11 | 0.10 | 0.09 | 0.08 | 0.07 | 0.07 | 0.06 | 0.06 | 0.05 | 0.05 | 0.05 | 0.05 | 0.04 |
| Administrative Expenses | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Cents/KWh | 18.00 | 18.00 | 64.69 | 23.29 | 38.78 | 17.74 | 28.49 | 15.33 | 22.95 | 13.97 | 20.36 | 13.87 | 18.17 | 13.30 | 16.65 | 12.93 | 15.52 | 12.65 | 14.67 | 12.46 | 13.30 |
| Cents/KWh (with profit) | 19.53 | 19.53 | 70.16 | 25.26 | 42.06 | 19.24 | 30.90 | 16.63 | 24.89 | 15.15 | 22.08 | 15.04 | 19.71 | 14.43 | 18.06 | 14.02 | 16.83 | 13.72 | 15.91 | 13.51 | 14.42 |

SCENARIO #1 CONT.

RESIDUAL FUEL OIL POWER GENERATION

| YEAR | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oil Facility Development Timetable(Mw) | | | | | 100 | | | | 100 | | | | 100 | | | | 100 | | | | 100 |
| Total Net Capacity Development | | | | | 100 | 100 | 100 | 100 | 200 | 200 | 200 | 200 | 300 | 300 | 300 | 300 | 400 | 400 | 400 | 400 | 500 |
| Oil Price ($ bbl) | | | | | 25.00 | 26.00 | 27.04 | 28.12 | 29.25 | 30.42 | 31.63 | 32.90 | 34.21 | 35.58 | 37.01 | 38.49 | 40.03 | 41.63 | 43.29 | 45.02 | 45.02 |
| Electricity Produced (1000MWh) | | | | | 701 | 701 | 701 | 701 | 1402 | 1402 | 1402 | 1402 | 2102 | 2102 | 2102 | 2102 | 2803 | 2803 | 2803 | 2803 | 3504 |
| Oil Consumed (M bbl) | | | | | 1.08 | 1.08 | 1.08 | 1.08 | 2.17 | 2.17 | 2.17 | 2.17 | 3.25 | 3.25 | 3.25 | 3.25 | 4.34 | 4.34 | 4.34 | 4.34 | 5.42 |
| **COST FOR NEW OIL GENERATION FACILITIES** | | | | | | | | | | | | | | | | | | | | | |
| Capital | 9.2 | 9.2 | 9.2 | 9.2 | 18.4 | 18.4 | 18.4 | 18.4 | 27.6 | 27.6 | 27.6 | 27.6 | 36.7 | 36.7 | 36.7 | 36.7 | 45.9 | 45.9 | 45.9 | 45.9 | 45.9 |
| O&M | | | | | 2.1 | 2.1 | 2.1 | 2.1 | 4.3 | 4.3 | 4.3 | 4.3 | 6.4 | 6.4 | 6.4 | 6.4 | 8.6 | 8.6 | 8.6 | 8.6 | 10.7 |
| Fuel | | | | | 27.1 | 28.2 | 29.3 | 30.5 | 63.4 | 66.0 | 68.6 | 71.4 | 111.3 | 115.8 | 120.4 | 125.2 | 173.7 | 180.6 | 187.8 | 195.4 | 244.2 |
| Administrative Expenses (M$) | | | | | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.6 | 0.6 | 0.8 |
| Cost (M$) | 9.2 | 9.2 | 9.2 | 9.2 | 47.8 | 48.9 | 50.0 | 51.2 | 95.6 | 98.1 | 100.8 | 103.5 | 155.0 | 159.4 | 164.0 | 168.9 | 228.8 | 235.7 | 242.9 | 250.4 | 301.6 |
| With Profit (M$) | 9.2 | 9.2 | 9.2 | 9.2 | 51.8 | 53.0 | 54.2 | 55.5 | 103.7 | 106.4 | 109.3 | 112.3 | 168.1 | 172.9 | 177.9 | 183.1 | 248.1 | 255.6 | 263.5 | 271.6 | 327.1 |
| Cents/KWh (oil) | | | | | | | | | | | | | | | | | | | | | |
| Capital | 1.31 | 1.31 | 1.31 | 1.31 | 2.62 | 2.62 | 2.62 | 2.62 | 1.97 | 1.97 | 1.97 | 1.97 | 1.75 | 1.75 | 1.75 | 1.75 | 1.64 | 1.64 | 1.64 | 1.64 | 1.31 |
| O&M | | | | | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 |
| Fuel | | | | | 3.87 | 4.02 | 4.19 | 4.35 | 4.53 | 4.71 | 4.90 | 5.09 | 5.30 | 5.51 | 5.73 | 5.96 | 6.20 | 6.44 | 6.70 | 6.97 | 6.97 |
| Administrative Expenses | | | | | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Total Cents/KWh | 1.31 | 1.31 | 1.31 | 1.31 | 6.82 | 6.97 | 7.13 | 7.30 | 6.82 | 7.00 | 7.19 | 7.39 | 7.37 | 7.58 | 7.80 | 8.03 | 8.16 | 8.41 | 8.67 | 8.93 | 8.61 |
| Total Cents/KWh with profit | 1.42 | 1.42 | 1.42 | 1.42 | 7.39 | 7.56 | 7.74 | 7.92 | 7.40 | 7.59 | 7.80 | 8.01 | 7.99 | 8.22 | 8.46 | 8.71 | 8.85 | 9.12 | 9.40 | 9.69 | 9.33 |

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SOLAR/RESIDUAL FUEL OIL POWER GENERATION

| YEAR | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Solar/Oil Development Timetable(MW) | | | | | 100 | | | | 100 | | | | 100 | | | | 100 | | | | 100 |
| Total Net Capacity Development | | | | | 100 | 100 | 100 | 100 | 200 | 200 | 200 | 200 | 300 | 300 | 300 | 300 | 400 | 400 | 400 | 400 | 500 |
| Electricity Produced (1000MWh) | | | | | 701 | 701 | 701 | 701 | 1402 | 1402 | 1402 | 1402 | 2102 | 2102 | 2102 | 2102 | 2803 | 2803 | 2803 | 2803 | 3504 |
| Solar Produced Electricity (1000MWh) | | 301 | | | 210 | 210 | 210 | 210 | 420 | 420 | 420 | 420 | 631 | 631 | 631 | 631 | 841 | 841 | 841 | 841 | 1051 |
| Oil Price ($ bbl) | | | | | 25.00 | 26.00 | 27.04 | 28.12 | 29.25 | 30.42 | 31.63 | 32.90 | 34.21 | 35.58 | 37.01 | 38.49 | 40.03 | 41.63 | 43.29 | 45.02 | 45.02 |
| Oil Produced Electricity (1000MWh) | | 701 | | | 491 | 491 | 491 | 491 | 981 | 981 | 981 | 981 | 1472 | 1472 | 1472 | 1472 | 1962 | 1962 | 1962 | 1962 | 2453 |
| Oil Consumed (M bbl) | | | | | 0.76 | 0.76 | 0.76 | 0.76 | 1.52 | 1.52 | 1.52 | 1.52 | 2.28 | 2.28 | 2.28 | 2.28 | 3.04 | 3.04 | 3.04 | 3.04 | 3.80 |
| **COST FOR SOLAR/OIL GENERATION FACILITIES** | | | | | | | | | | | | | | | | | | | | | |
| Capital | 35.4 | 35.4 | 35.4 | 35.4 | 70.7 | 70.7 | 70.7 | 70.7 | 106.1 | 106.1 | 106.1 | 106.1 | 141.5 | 141.5 | 141.5 | 141.5 | 176.8 | 176.8 | 176.8 | 176.8 | 176.8 |
| O&M | | | | | 7.1 | 7.1 | 7.1 | 7.1 | 14.1 | 14.1 | 14.1 | 14.1 | 21.2 | 21.2 | 21.2 | 21.2 | 28.2 | 28.2 | 28.2 | 28.2 | 35.3 |
| Fuel | | | | | 19.0 | 19.7 | 20.5 | 21.4 | 44.4 | 46.2 | 48.0 | 50.0 | 77.9 | 81.1 | 84.3 | 87.7 | 121.6 | 126.4 | 131.5 | 136.7 | 170.9 |
| Administrative Expenses (M$) | | | | | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.6 | 0.6 | 0.8 |
| Cost (M$) | 35.4 | 35.4 | 35.4 | 35.4 | 96.9 | 97.7 | 98.5 | 99.3 | 164.9 | 166.7 | 168.5 | 170.5 | 241.0 | 244.1 | 247.4 | 250.7 | 327.2 | 332.1 | 337.1 | 342.4 | 383.8 |
| With Profit (M$) | 35.4 | 35.4 | 35.4 | 35.4 | 105.1 | 105.9 | 106.8 | 107.7 | 178.9 | 180.8 | 182.8 | 184.9 | 261.4 | 264.8 | 268.3 | 271.9 | 354.9 | 360.1 | 365.6 | 371.3 | 416.2 |
| Cents/KWh | | | | | | | | | | | | | | | | | | | | | |
| Capital | 5.05 | 5.05 | 5.05 | 5.05 | 10.09 | 10.09 | 10.09 | 10.09 | 7.57 | 7.57 | 7.57 | 7.57 | 6.73 | 6.73 | 6.73 | 6.73 | 6.31 | 6.31 | 6.31 | 6.31 | 5.05 |
| O&M | | | | | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 |
| Fuel | | | | | 2.71 | 2.82 | 2.93 | 3.05 | 3.17 | 3.30 | 3.43 | 3.56 | 3.71 | 3.86 | 4.01 | 4.17 | 4.34 | 4.51 | 4.69 | 4.88 | 4.88 |
| Administrative Expenses | | | | | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Total Cents/KWh | 5.05 | 5.05 | 5.05 | 5.05 | 13.83 | 13.94 | 14.05 | 14.17 | 11.77 | 11.89 | 12.02 | 12.16 | 11.46 | 11.61 | 11.77 | 11.93 | 11.67 | 11.85 | 12.03 | 12.21 | 10.95 |
| Total Cents/KWh with profit | 5.47 | 5.47 | 5.47 | 5.47 | 15.00 | 15.12 | 15.24 | 15.37 | 12.76 | 12.90 | 13.04 | 13.19 | 12.43 | 12.59 | 12.76 | 12.93 | 12.66 | 12.85 | 13.04 | 13.25 | 11.88 |

SCENARIO 01 CONT.

GEOTHERMAL POWER GENERATION

| YEAR | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Geothermal Development Timetable(MW) | | | | | | | | | | | | | | | | | | | |
| Total Net Capacity Development | 450 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 450 | 500 | 500 | 500 | 450 | 450 | 500 | 500 | 500 | 500 | 500 |
| Electricity Produced (1000MWh) | 3154 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3154 | 3504 | 3504 | 3504 | 3154 | 3154 | 3504 | 3504 | 3504 | 3504 | 3504 |
| COST FOR GEOTHERMAL POWER PROJECT | | | | | | | | | | | | | | | | | | | |
| Geothermal Plants (M$) | | | | | | | | | | | | | | | | | | | |
| Capital | 195.9 | 195.9 | 195.9 | 185.0 | 185.0 | 174.1 | 174.1 | 152.4 | 130.6 | 119.7 | 119.7 | 98.0 | 76.2 | 65.3 | 65.3 | 54.4 | 54.4 | 32.7 | 32.7 |
| Replacement Wells | 36.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 |
| O&M | 55.8 | 55.8 | 55.8 | 55.8 | 55.8 | 55.8 | 55.8 | 55.8 | 55.8 | 55.8 | 55.8 | 55.8 | 55.8 | 55.8 | 55.8 | 55.8 | 55.8 | 55.8 | 55.8 |
| Royalty Payments | 27.1 | 30.2 | 30.2 | 29.2 | 29.2 | 29.2 | 29.2 | 28.3 | 25.5 | 28.3 | 28.3 | 27.4 | 24.7 | 24.7 | 27.4 | 26.5 | 26.5 | 26.5 | 26.5 |
| Rent | 10.9 | 12.1 | 12.1 | 11.7 | 11.7 | 11.7 | 11.7 | 11.3 | 10.2 | 11.3 | 11.3 | 11.0 | 9.9 | 9.9 | 11.0 | 10.6 | 10.6 | 10.6 | 10.6 |
| Plant Replacement Fund | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -49.6 | -51.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cables and Facilities (M$) | | | | | | | | | | | | | | | | | | | |
| Capital | 45.3 | 45.3 | 45.3 | 18.5 | 18.5 | 18.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| O&M | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Administrative Expenses (M$) | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| Cost (M$) | 373.6 | 381.9 | 381.9 | 342.8 | 342.8 | 331.9 | 263.9 | 239.0 | 264.7 | 257.8 | 257.8 | 234.7 | 209.1 | 198.2 | 202.1 | 189.9 | 189.9 | 168.1 | 168.1 |
| With profit (M$) | 405.2 | 414.2 | 414.2 | 371.8 | 371.8 | 360.0 | 286.2 | 259.2 | 287.1 | 279.6 | 279.6 | 254.6 | 226.8 | 215.0 | 219.2 | 206.0 | 206.0 | 182.3 | 182.3 |
| Cents/KWh (geothermal) | | | | | | | | | | | | | | | | | | | |
| Geothermal Plants | | | | | | | | | | | | | | | | | | | |
| Capital | 6.21 | 5.59 | 5.59 | 5.28 | 5.28 | 4.97 | 4.97 | 4.35 | 4.14 | 3.42 | 3.42 | 2.80 | 2.42 | 2.07 | 1.86 | 1.55 | 1.55 | 0.93 | 0.93 |
| Replacement Wells | 1.16 | 1.16 | 1.16 | 1.16 | 1.16 | 1.16 | 1.16 | 1.16 | 1.28 | 1.16 | 1.16 | 1.16 | 1.28 | 1.28 | 1.16 | 1.16 | 1.16 | 1.16 | 1.16 |
| O&M | 1.77 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.77 | 1.59 | 1.59 | 1.59 | 1.77 | 1.77 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 |
| Royalty Payments | 0.86 | 0.86 | 0.86 | 0.83 | 0.83 | 0.83 | 0.83 | 0.81 | 0.81 | 0.81 | 0.81 | 0.78 | 0.78 | 0.78 | 0.78 | 0.76 | 0.76 | 0.76 | 0.76 |
| Rent | 0.34 | 0.34 | 0.34 | 0.33 | 0.33 | 0.33 | 0.33 | 0.32 | 0.32 | 0.32 | 0.32 | 0.31 | 0.31 | 0.31 | 0.31 | 0.30 | 0.30 | 0.30 | 0.30 |
| Plant Replacement Fund | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -1.42 | -1.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Cables and Facilities | | | | | | | | | | | | | | | | | | | |
| Capital | 1.44 | 1.29 | 1.29 | 0.53 | 0.53 | 0.53 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| O&M | 0.05 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.05 | 0.04 | 0.04 | 0.04 | 0.05 | 0.05 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 |
| Administrative Expenses | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Cents/KWh | 11.85 | 10.90 | 10.90 | 9.78 | 9.78 | 9.47 | 7.53 | 6.82 | 8.39 | 7.36 | 7.36 | 6.70 | 6.63 | 6.29 | 5.77 | 5.42 | 5.42 | 4.80 | 4.80 |
| Cents/KWh (with profit) | 12.85 | 11.82 | 11.82 | 10.61 | 10.61 | 10.27 | 8.17 | 7.40 | 9.10 | 7.98 | 7.98 | 7.27 | 7.19 | 6.82 | 6.25 | 5.88 | 5.88 | 5.20 | 5.20 |

SCENARIO #1 CONT.

RESIDUAL FUEL OIL POWER GENERATION

| YEAR | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oil Facility Development Timetable(MW) | | | | | | | | | | | | | | | | | | | |
| Total Net Capacity Development | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| Oil Price ($ bbl) | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 |
| Electricity Produced (1000MWh) | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 |
| Oil Consumed (M bbl) | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 |
| COST FOR NEW OIL GENERATION FACILITIES | | | | | | | | | | | | | | | | | | | |
| Capital | 45.9 | 45.9 | 45.9 | 36.7 | 36.7 | 36.7 | 36.7 | 27.6 | 27.6 | 27.6 | 27.6 | 18.4 | 18.4 | 18.4 | 18.4 | 9.2 | 9.2 | 9.2 | 9.2 |
| O&M | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 |
| Fuel | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 |
| Administrative Expenses (M$) | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| Cost (M$) | 301.6 | 301.6 | 301.6 | 292.4 | 292.4 | 292.4 | 292.4 | 283.2 | 283.2 | 283.2 | 283.2 | 274.0 | 274.0 | 274.0 | 274.0 | 264.8 | 264.8 | 264.8 | 264.8 |
| With Profit (M$) | 327.1 | 327.1 | 327.1 | 317.1 | 317.1 | 317.1 | 317.1 | 307.1 | 307.1 | 307.1 | 307.1 | 297.2 | 297.2 | 297.2 | 297.2 | 287.2 | 287.2 | 287.2 | 287.2 |
| Cents/KWh (oil) | | | | | | | | | | | | | | | | | | | |
| Capital | 1.31 | 1.31 | 1.31 | 1.05 | 1.05 | 1.05 | 1.05 | 0.79 | 0.79 | 0.79 | 0.79 | 0.52 | 0.52 | 0.52 | 0.52 | 0.26 | 0.26 | 0.26 | 0.26 |
| O&M | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 |
| Fuel | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 |
| Administrative Expenses | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Total Cents/KWh | 8.61 | 8.61 | 8.61 | 8.34 | 8.34 | 8.34 | 8.34 | 8.08 | 8.08 | 8.08 | 8.08 | 7.82 | 7.82 | 7.82 | 7.82 | 7.56 | 7.56 | 7.56 | 7.56 |
| Total Cents/KWh with profit | 9.33 | 9.33 | 9.33 | 9.05 | 9.05 | 9.05 | 9.05 | 8.77 | 8.77 | 8.77 | 8.77 | 8.48 | 8.48 | 8.48 | 8.48 | 8.20 | 8.20 | 8.20 | 8.20 |

SOLAR/RESIDUAL FUEL OIL POWER GENERATION

| YEAR | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Solar/Oil Development Timetable(MW) | | | | | | | | | | | | | | | | | | | |
| Total Net Capacity Development | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| Electricity Produced (1000MWh) | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 |
| Solar Produced Electricity (1000MWh) | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 |
| Oil Price ($ bbl) | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 |
| Oil Produced Electricity (1000MWh) | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 |
| Oil Consumed (M bbl) | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 |
| COST FOR SOLAR/OIL GENERATION FACILITIES | | | | | | | | | | | | | | | | | | | |
| Capital | 176.8 | 176.8 | 176.8 | 141.5 | 141.5 | 141.5 | 141.5 | 106.1 | 106.1 | 106.1 | 106.1 | 70.7 | 70.7 | 70.7 | 70.7 | 35.4 | 35.4 | 35.4 | 35.4 |
| O&M | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 |
| Fuel | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 |
| Administrative Expenses (M$) | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| Cost (M$) | 383.8 | 383.8 | 383.8 | 348.4 | 348.4 | 348.4 | 348.4 | 313.0 | 313.0 | 313.0 | 313.0 | 277.7 | 277.7 | 277.7 | 277.7 | 242.3 | 242.3 | 242.3 | 242.3 |
| With Profit (M$) | 416.2 | 416.2 | 416.2 | 377.9 | 377.9 | 377.9 | 377.9 | 339.5 | 339.5 | 339.5 | 339.5 | 301.2 | 301.2 | 301.2 | 301.2 | 262.8 | 262.8 | 262.8 | 262.8 |
| Cents/KWh | | | | | | | | | | | | | | | | | | | |
| Capital | 5.05 | 5.05 | 5.05 | 4.04 | 4.04 | 4.04 | 4.04 | 3.03 | 3.03 | 3.03 | 3.03 | 2.02 | 2.02 | 2.02 | 2.02 | 1.01 | 1.01 | 1.01 | 1.01 |
| O&M | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 |
| Fuel | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 |
| Administrative Expenses | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Total Cents/KWh | 10.95 | 10.95 | 10.95 | 9.94 | 9.94 | 9.94 | 9.94 | 8.93 | 8.93 | 8.93 | 8.93 | 7.92 | 7.92 | 7.92 | 7.92 | 6.92 | 6.92 | 6.92 | 6.92 |
| Total Cents/KWh with profit | 11.88 | 11.88 | 11.88 | 10.78 | 10.78 | 10.78 | 10.78 | 9.69 | 9.69 | 9.69 | 9.69 | 8.59 | 8.59 | 8.59 | 8.59 | 7.50 | 7.50 | 7.50 | 7.50 |

## SCENARIO 2

25 MW power plants using
high plant/wellfield costs and a
20% contingency

SCENARIO #2: 25 MW GEOTHERMAL PLANTS, HIGH PLANT COSTS, FUEL OIL PRICE STABILIZES AT $45.00 PER BARREL IN 21ST YEAR OF PROJECT

| GEOTHERMAL POWER GENERATION | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 |
| Geothermal Development Timetable(MW) | | | 50 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| Total Net Capacity Development | | | 50 | 75 | 100 | 125 | 150 | 175 | 200 | 225 | 250 | 275 | 300 | 325 | 350 | 375 | 400 | 425 | 450 | 475 | 500 |
| Electricity Produced (1000MWh) | | | 350 | 526 | 701 | 876 | 1051 | 1226 | 1402 | 1577 | 1752 | 1927 | 2102 | 2278 | 2453 | 2628 | 2803 | 2978 | 3154 | 3329 | 3504 |
| COST FOR GEOTHERMAL POWER PROJECT | | | | | | | | | | | | | | | | | | | | | |
| Geothermal Plants (M$) | | | | | | | | | | | | | | | | | | | | | |
| Capital | 26.1 | 26.1 | 52.3 | 52.3 | 78.4 | 78.4 | 104.5 | 104.5 | 130.7 | 130.7 | 156.8 | 156.8 | 182.9 | 182.9 | 209.1 | 209.1 | 235.2 | 235.2 | 261.3 | 261.3 | 261.3 |
| Replacement Wells | | | | | 5.4 | 5.4 | 10.8 | 10.8 | 16.2 | 16.2 | 21.6 | 21.6 | 27.0 | 27.0 | 32.4 | 32.4 | 37.8 | 37.8 | 43.2 | 43.2 | 48.6 |
| O&M | | | 9.6 | 14.4 | 19.2 | 24.1 | 28.9 | 33.7 | 38.5 | 43.3 | 48.1 | 52.9 | 57.7 | 62.5 | 67.3 | 72.2 | 77.0 | 81.8 | 86.6 | 91.4 | 96.2 |
| Royalty Payments | | | | | | | | | | | 12.6 | 14.2 | 15.5 | 17.3 | 19.1 | 21.1 | 22.9 | 25.0 | 27.3 | 29.7 | 30.2 |
| Rent | 1.0 | 1.0 | 1.0 | 1.4 | 1.9 | 2.4 | 3.0 | 3.6 | 3.8 | 4.4 | 5.0 | 5.7 | 6.2 | 6.9 | 7.7 | 8.4 | 9.2 | 10.0 | 10.9 | 11.9 | 12.1 |
| Plant Replacement Fund | | | 156.8 | 0.0 | 130.8 | 0.0 | 133.3 | 0.0 | 121.5 | 0.0 | 109.7 | 0.0 | 97.9 | 0.0 | 86.1 | 0.0 | 74.3 | 0.0 | 62.5 | 0.0 | 50.7 |
| Cables and Facilities (M$) | | | | | | | | | | | | | | | | | | | | | |
| Capital | 40.3 | 40.3 | 40.3 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 |
| O&M | | | 1.0 | 1.0 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Administrative Expenses (M$) | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 |
| Cost (M$) | 67.5 | 67.5 | 261.0 | 137.2 | 313.4 | 179.9 | 350.1 | 222.3 | 380.4 | 264.3 | 423.6 | 321.1 | 457.1 | 366.5 | 491.6 | 413.1 | 526.3 | 459.8 | 561.9 | 507.6 | 569.2 |
| With profit (M$) | 73.2 | 73.2 | 283.1 | 148.8 | 339.9 | 195.2 | 379.7 | 241.1 | 412.5 | 286.7 | 459.4 | 348.2 | 495.8 | 397.5 | 533.2 | 448.0 | 570.8 | 498.7 | 609.5 | 550.5 | 617.3 |
| Cents/KWh (geothermal) | | | | | | | | | | | | | | | | | | | | | |
| Geothermal Plants | | | | | | | | | | | | | | | | | | | | | |
| Capital | 7.46 | 7.46 | 14.92 | 9.94 | 11.19 | 8.95 | 9.94 | 8.52 | 9.32 | 8.29 | 8.95 | 8.14 | 8.70 | 8.03 | 8.52 | 7.95 | 8.39 | 7.90 | 8.29 | 7.85 | 7.46 |
| Replacement Wells | | | | | 0.77 | 0.62 | 1.03 | 0.88 | 1.16 | 1.03 | 1.23 | 1.12 | 1.28 | 1.19 | 1.32 | 1.23 | 1.35 | 1.27 | 1.37 | 1.30 | 1.39 |
| O&M | | | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 |
| Royalty Payments | | | | | | | | | | | 0.72 | 0.74 | 0.74 | 0.76 | 0.78 | 0.80 | 0.82 | 0.84 | 0.87 | 0.89 | 0.86 |
| Rent | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.28 | 0.29 | 0.29 | 0.27 | 0.28 | 0.29 | 0.30 | 0.29 | 0.30 | 0.31 | 0.32 | 0.33 | 0.34 | 0.35 | 0.36 | 0.34 |
| Plant Replacement Fund | | 0.00 | 44.76 | 0.00 | 19.81 | 0.00 | 12.68 | 0.00 | 8.67 | 0.00 | 6.26 | 0.00 | 4.66 | 0.00 | 3.51 | 0.00 | 2.65 | 0.00 | 1.90 | 0.00 | 1.45 |
| Cables and Facilities | | | | | | | | | | | | | | | | | | | | | |
| Capital | 11.50 | 11.50 | 11.50 | 12.94 | 9.70 | 7.76 | 6.47 | 5.55 | 4.85 | 4.31 | 3.88 | 3.53 | 3.23 | 2.99 | 2.77 | 2.59 | 2.43 | 2.28 | 2.16 | 2.04 | 1.94 |
| O&M | | | 0.29 | 0.19 | 0.21 | 0.17 | 0.14 | 0.12 | 0.11 | 0.10 | 0.09 | 0.08 | 0.07 | 0.07 | 0.06 | 0.06 | 0.05 | 0.05 | 0.05 | 0.05 | 0.04 |
| Administrative Expenses | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Cents/KWh | 19.25 | 19.25 | 74.50 | 26.11 | 44.72 | 20.54 | 33.31 | 18.13 | 27.14 | 16.76 | 24.18 | 16.66 | 21.74 | 16.09 | 20.04 | 15.72 | 18.77 | 15.44 | 17.82 | 15.25 | 16.24 |
| Cents/KWh (with profit) | 20.88 | 20.88 | 80.80 | 28.32 | 48.50 | 22.28 | 36.12 | 19.66 | 29.43 | 18.18 | 26.22 | 18.07 | 23.58 | 17.45 | 21.74 | 17.05 | 20.36 | 16.74 | 19.33 | 16.54 | 17.62 |

SCENARIO #2 CONT.

RESIDUAL FUEL OIL POWER GENERATION

| YEAR | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oil Facility Development Timetable(MW) | | | | | 100 | | | | 100 | | | | 100 | | | | 100 | | | | 100 |
| Total Net Capacity Development | | | | | 100 | 100 | 100 | 100 | 200 | 200 | 200 | 200 | 300 | 300 | 300 | 300 | 400 | 400 | 400 | 400 | 500 |
| Oil Price ($ bbl) | | | | | 25.00 | 26.00 | 27.04 | 28.12 | 29.25 | 30.42 | 31.63 | 32.90 | 34.21 | 35.58 | 37.01 | 38.49 | 40.03 | 41.63 | 43.29 | 45.02 | 45.02 |
| Electricity Produced (1000MWh) | | | | | 701 | 701 | 701 | 701 | 1402 | 1402 | 1402 | 1403 | 2102 | 2102 | 2102 | 2102 | 2803 | 2803 | 2803 | 2803 | 3504 |
| Oil Consumed (M bbl) | | | | | 1.08 | 1.08 | 1.08 | 1.08 | 2.17 | 2.17 | 2.17 | 2.17 | 3.25 | 3.25 | 3.25 | 3.25 | 4.34 | 4.34 | 4.34 | 4.34 | 5.42 |
| COST FOR NEW OIL GENERATION FACILITIES | | | | | | | | | | | | | | | | | | | | | |
| Capital | 9.2 | 9.2 | 9.2 | 9.2 | 18.4 | 18.4 | 18.4 | 18.4 | 27.6 | 27.6 | 27.6 | 27.6 | 36.7 | 36.7 | 36.7 | 36.7 | 45.9 | 45.9 | 45.9 | 45.9 | 45.9 |
| O&M | | | | | 2.1 | 2.1 | 2.1 | 2.1 | 4.3 | 4.3 | 4.3 | 4.3 | 6.4 | 6.4 | 6.4 | 6.4 | 8.6 | 8.6 | 8.6 | 8.6 | 10.7 |
| Fuel | | | | | 27.1 | 28.2 | 29.3 | 30.5 | 63.4 | 66.0 | 68.6 | 71.4 | 111.3 | 115.8 | 120.4 | 125.2 | 173.7 | 180.6 | 187.8 | 195.4 | 244.2 |
| Administrative Expenses (M$) | | | | | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.6 | 0.6 | 0.8 |
| Cost (M$) | 9.2 | 9.2 | 9.2 | 9.2 | 47.8 | 48.9 | 50.0 | 51.2 | 95.6 | 98.1 | 100.8 | 103.5 | 155.0 | 159.4 | 164.0 | 168.9 | 228.8 | 235.7 | 242.9 | 250.4 | 301.6 |
| With Profit (M$) | 9.2 | 9.2 | 9.2 | 9.2 | 51.0 | 53.0 | 54.2 | 55.5 | 103.7 | 106.4 | 109.3 | 112.3 | 168.1 | 172.9 | 177.9 | 183.1 | 248.1 | 255.6 | 263.5 | 271.6 | 327.1 |
| Cents/KWh (oil) | | | | | | | | | | | | | | | | | | | | | |
| Capital | 1.31 | 1.31 | 1.31 | 1.31 | 2.62 | 2.62 | 2.62 | 2.62 | 1.97 | 1.97 | 1.97 | 1.97 | 1.75 | 1.75 | 1.75 | 1.75 | 1.64 | 1.64 | 1.64 | 1.64 | 1.31 |
| O&M | | | | | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 |
| Fuel | | | | | 3.87 | 4.02 | 4.19 | 4.35 | 4.53 | 4.71 | 4.90 | 5.09 | 5.30 | 5.51 | 5.73 | 5.96 | 6.20 | 6.44 | 6.70 | 6.97 | 6.97 |
| Administrative Expenses | | | | | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Total Cents/KWh | 1.31 | 1.31 | 1.31 | 1.31 | 6.82 | 6.97 | 7.13 | 7.30 | 6.82 | 7.00 | 7.19 | 7.39 | 7.37 | 7.58 | 7.80 | 8.03 | 8.16 | 8.41 | 8.67 | 8.93 | 8.61 |
| Total Cents/KWh with profit | 1.42 | 1.42 | 1.42 | 1.42 | 7.39 | 7.56 | 7.74 | 7.92 | 7.40 | 7.59 | 7.80 | 8.01 | 7.99 | 8.22 | 8.46 | 8.71 | 8.85 | 9.12 | 9.40 | 9.69 | 9.33 |

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SOLAR/RESIDUAL FUEL OIL POWER GENERATION

| YEAR | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Solar/Oil Development Timetable(MW) | | | | | 100 | | | | 100 | | | | 100 | | | | 100 | | | | 100 |
| Total Net Capacity Development | | | | | 100 | 100 | 100 | 100 | 200 | 200 | 200 | 200 | 300 | 300 | 300 | 300 | 400 | 400 | 400 | 400 | 500 |
| Electricity Produced (1000MWh) | | | | | 701 | 701 | 701 | 701 | 1402 | 1402 | 1402 | 1402 | 2102 | 2102 | 2102 | 2102 | 2803 | 2803 | 2803 | 2803 | 3504 |
| Solar Produced Electricity (1000MWh) | | 301 | | | 210 | 210 | 210 | 210 | 420 | 420 | 420 | 420 | 631 | 631 | 631 | 631 | 841 | 841 | 841 | 841 | 1051 |
| Oil Price ($ bbl) | | | | | 25.00 | 26.00 | 27.04 | 28.12 | 29.25 | 30.42 | 31.63 | 32.90 | 34.21 | 35.58 | 37.01 | 38.49 | 40.03 | 41.63 | 43.29 | 45.02 | 45.02 |
| Oil Produced Electricity (1000MWh) | | 701 | | | 491 | 491 | 491 | 491 | 981 | 981 | 981 | 981 | 1472 | 1472 | 1472 | 1472 | 1962 | 1962 | 1962 | 1962 | 2453 |
| Oil Consumed (M bbl) | | | | | 0.76 | 0.76 | 0.76 | 0.76 | 1.52 | 1.52 | 1.52 | 1.52 | 2.28 | 2.28 | 2.28 | 2.28 | 3.04 | 3.04 | 3.04 | 3.04 | 3.80 |
| COST FOR SOLAR/OIL GENERATION FACILITIES | | | | | | | | | | | | | | | | | | | | | |
| Capital | 35.4 | 35.4 | 35.4 | 35.4 | 70.7 | 70.7 | 70.7 | 70.7 | 106.1 | 106.1 | 106.1 | 106.1 | 141.5 | 141.5 | 141.5 | 141.5 | 176.8 | 176.8 | 176.8 | 176.8 | 176.8 |
| O&M | | | | | 7.1 | 7.1 | 7.1 | 7.1 | 14.1 | 14.1 | 14.1 | 14.1 | 21.2 | 21.2 | 21.2 | 21.2 | 28.2 | 28.2 | 28.2 | 28.2 | 35.3 |
| Fuel | | | | | 19.0 | 19.7 | 20.5 | 21.4 | 44.4 | 46.2 | 48.0 | 50.0 | 77.9 | 81.1 | 84.3 | 87.7 | 121.6 | 126.4 | 131.5 | 136.7 | 170.9 |
| Administrative Expenses (M$) | | | | | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.6 | 0.6 | 0.8 |
| Cost (M$) | 35.4 | 35.4 | 35.4 | 35.4 | 96.9 | 97.7 | 98.5 | 99.3 | 164.9 | 166.7 | 168.5 | 170.5 | 241.0 | 244.1 | 247.4 | 250.7 | 327.2 | 332.1 | 337.1 | 342.4 | 383.8 |
| With Profit (M$) | 35.4 | 35.4 | 35.4 | 35.4 | 105.1 | 105.9 | 106.8 | 107.7 | 178.9 | 180.8 | 182.8 | 184.9 | 261.4 | 264.8 | 268.3 | 271.9 | 354.9 | 360.1 | 365.6 | 371.3 | 416.2 |
| Cents/KWh | | | | | | | | | | | | | | | | | | | | | |
| Capital | 5.05 | 5.05 | 5.05 | 5.05 | 10.09 | 10.09 | 10.09 | 10.09 | 7.57 | 7.57 | 7.57 | 7.57 | 6.73 | 6.73 | 6.73 | 6.73 | 6.31 | 6.31 | 6.31 | 6.31 | 5.05 |
| O&M | | | | | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 |
| Fuel | | | | | 2.71 | 2.82 | 2.93 | 3.05 | 3.17 | 3.30 | 3.43 | 3.56 | 3.71 | 3.86 | 4.01 | 4.17 | 4.34 | 4.51 | 4.69 | 4.88 | 4.88 |
| Administrative Expenses | | | | | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Total Cents/KWh | 5.05 | 5.05 | 5.05 | 5.05 | 13.83 | 13.94 | 14.05 | 14.17 | 11.77 | 11.89 | 12.02 | 12.16 | 11.46 | 11.61 | 11.77 | 11.93 | 11.67 | 11.85 | 12.03 | 12.21 | 10.95 |
| Total Cents/KWh with profit | 5.47 | 5.47 | 5.47 | 5.47 | 15.00 | 15.12 | 15.24 | 15.37 | 12.76 | 12.90 | 13.04 | 13.19 | 12.43 | 12.59 | 12.76 | 12.93 | 12.66 | 12.85 | 13.04 | 13.25 | 11.88 |

SCENARIO 02 CONT.

GEOTHERMAL POWER GENERATION

| YEAR | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Geothermal Development Timetable(MW) | | | | | | | | | | | | | | | | | | | |
| Total Net Capacity Development | 450 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 450 | 500 | 500 | 500 | 450 | 450 | 500 | 500 | 500 | 500 | 500 |
| Electricity Produced (1000MWh) | 3154 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3154 | 3504 | 3504 | 3504 | 3154 | 3154 | 3504 | 3504 | 3504 | 3504 | 3504 |
| COST FOR GEOTHERMAL POWER PROJECT | | | | | | | | | | | | | | | | | | | |
| Geothermal Plants (M$) | | | | | | | | | | | | | | | | | | | |
| Capital | 235.2 | 235.2 | 235.2 | 222.1 | 222.1 | 209.1 | 209.1 | 182.9 | 156.8 | 143.7 | 143.7 | 117.6 | 91.5 | 78.4 | 78.4 | 65.3 | 65.3 | 39.2 | 39.2 |
| Replacement Wells | 48.6 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 |
| O&M | 96.2 | 96.2 | 96.2 | 96.2 | 96.2 | 96.2 | 96.2 | 96.2 | 96.2 | 96.2 | 96.2 | 96.2 | 96.2 | 96.2 | 96.2 | 96.2 | 96.2 | 96.2 | 96.2 |
| Royalty Payments | 27.1 | 30.2 | 30.2 | 29.2 | 29.2 | 29.2 | 29.2 | 28.3 | 25.5 | 28.3 | 28.3 | 27.4 | 24.7 | 24.7 | 27.4 | 26.5 | 26.5 | 26.5 | 26.5 |
| Rent | 10.9 | 12.1 | 12.1 | 11.7 | 11.7 | 11.7 | 11.7 | 11.3 | 10.2 | 11.3 | 11.3 | 11.0 | 9.9 | 9.9 | 11.0 | 10.6 | 10.6 | 10.6 | 10.6 |
| Plant Replacement Fund | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -57.5 | -59.7 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cables and Facilities (M$) | | | | | | | | | | | | | | | | | | | |
| Capital | 45.3 | 45.3 | 45.3 | 18.5 | 18.5 | 18.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| O&M | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Administrative Expenses (M$) | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| Cost (M$) | 465.4 | 475.0 | 475.0 | 433.8 | 433.8 | 420.8 | 344.7 | 315.2 | 344.8 | 335.7 | 335.7 | 308.3 | 278.3 | 265.2 | 269.1 | 254.7 | 254.7 | 228.6 | 228.6 |
| With profit (M$) | 504.8 | 515.2 | 515.2 | 470.5 | 470.5 | 456.3 | 373.9 | 341.9 | 373.9 | 364.1 | 364.1 | 334.3 | 301.8 | 287.7 | 291.8 | 276.2 | 276.2 | 247.9 | 247.9 |
| Cents/KWh (geothermal) | | | | | | | | | | | | | | | | | | | |
| Geothermal Plants | | | | | | | | | | | | | | | | | | | |
| Capital | 7.46 | 6.71 | 6.71 | 6.34 | 6.34 | 5.97 | 5.97 | 5.22 | 4.97 | 4.10 | 4.10 | 3.36 | 2.90 | 2.49 | 2.24 | 1.86 | 1.86 | 1.12 | 1.12 |
| Replacement Wells | 1.54 | 1.54 | 1.54 | 1.54 | 1.54 | 1.54 | 1.54 | 1.54 | 1.71 | 1.54 | 1.54 | 1.54 | 1.71 | 1.71 | 1.54 | 1.54 | 1.54 | 1.54 | 1.54 |
| O&M | 3.05 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 | 3.05 | 2.75 | 2.75 | 2.75 | 3.05 | 3.05 | 2.75 | 2.75 | 2.75 | 2.75 | 2.75 |
| Royalty Payments | 0.86 | 0.86 | 0.86 | 0.83 | 0.83 | 0.83 | 0.83 | 0.81 | 0.81 | 0.81 | 0.81 | 0.78 | 0.78 | 0.78 | 0.78 | 0.76 | 0.76 | 0.76 | 0.76 |
| Rent | 0.34 | 0.34 | 0.34 | 0.33 | 0.33 | 0.33 | 0.33 | 0.32 | 0.32 | 0.32 | 0.32 | 0.31 | 0.31 | 0.31 | 0.31 | 0.30 | 0.30 | 0.30 | 0.30 |
| Plant Replacement Fund | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -1.64 | -1.70 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Cables and Facilities | | | | | | | | | | | | | | | | | | | |
| Capital | 1.44 | 1.29 | 1.29 | 0.53 | 0.53 | 0.53 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| O&M | 0.05 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.05 | 0.04 | 0.04 | 0.04 | 0.05 | 0.05 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 |
| Administrative Expenses | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Cents/KWh | 14.76 | 13.56 | 13.56 | 12.38 | 12.38 | 12.01 | 9.84 | 9.00 | 10.93 | 9.58 | 9.58 | 8.80 | 8.82 | 8.41 | 7.68 | 7.27 | 7.27 | 6.52 | 6.52 |
| Cents/KWh (with profit) | 16.01 | 14.70 | 14.70 | 13.43 | 13.43 | 13.02 | 10.67 | 9.76 | 11.86 | 10.39 | 10.39 | 9.54 | 9.57 | 9.12 | 8.33 | 7.88 | 7.88 | 7.07 | 7.07 |

SCENARIO #2 CONT.

RESIDUAL FUEL OIL POWER GENERATION

| YEAR | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oil Facility Development Timetable(MW) | | | | | | | | | | | | | | | | | | | |
| Total Net Capacity Development | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| Oil Price ($/bbl) | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 |
| Electricity Produced (1000MWh) | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 |
| Oil Consumed (M bbl) | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 |
| COST FOR NEW OIL GENERATION FACILITIES | | | | | | | | | | | | | | | | | | | |
| Capital | 45.9 | 45.9 | 45.9 | 36.7 | 36.7 | 36.7 | 36.7 | 27.6 | 27.6 | 27.6 | 27.6 | 18.4 | 18.4 | 18.4 | 18.4 | 9.2 | 9.2 | 9.2 | 9.2 |
| O&M | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 |
| Fuel | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 |
| Administrative Expenses (M$) | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| Cost (M$) | 301.6 | 301.6 | 301.6 | 292.4 | 292.4 | 292.4 | 292.4 | 283.2 | 283.2 | 283.2 | 283.2 | 274.0 | 274.0 | 274.0 | 274.0 | 264.8 | 264.8 | 264.8 | 264.8 |
| With Profit (M$) | 327.1 | 327.1 | 327.1 | 317.1 | 317.1 | 317.1 | 317.1 | 307.1 | 307.1 | 307.1 | 307.1 | 297.2 | 297.2 | 297.2 | 297.2 | 287.2 | 287.2 | 287.2 | 287.2 |
| Cents/KWh (oil) | | | | | | | | | | | | | | | | | | | |
| Capital | 1.31 | 1.31 | 1.31 | 1.05 | 1.05 | 1.05 | 1.05 | 0.79 | 0.79 | 0.79 | 0.79 | 0.52 | 0.52 | 0.52 | 0.52 | 0.26 | 0.26 | 0.26 | 0.26 |
| O&M | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 |
| Fuel | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 |
| Administrative Expenses | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Total Cents/KWh | 8.61 | 8.61 | 8.61 | 8.34 | 8.34 | 8.34 | 8.34 | 8.08 | 8.08 | 8.08 | 8.08 | 7.82 | 7.82 | 7.82 | 7.82 | 7.56 | 7.56 | 7.56 | 7.56 |
| Total Cents/KWh with profit | 9.33 | 9.33 | 9.33 | 9.05 | 9.05 | 9.05 | 9.05 | 8.77 | 8.77 | 8.77 | 8.77 | 8.48 | 8.48 | 8.48 | 8.48 | 8.20 | 8.20 | 8.20 | 8.20 |

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SOLAR/RESIDUAL FUEL OIL POWER GENERATION

| YEAR | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Solar/Oil Development Timetable(MW) | | | | | | | | | | | | | | | | | | | |
| Total Net Capacity Development | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| Electricity Produced (1000MWh) | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 |
| Solar Produced Electricity (1000MWh) | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 |
| Oil Price ($/bbl) | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 |
| Oil Produced Electricity (1000MWh) | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 |
| Oil Consumed (M bbl) | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 |
| COST FOR SOLAR/OIL GENERATION FACILITIES | | | | | | | | | | | | | | | | | | | |
| Capital | 176.8 | 176.8 | 176.8 | 141.5 | 141.5 | 141.5 | 141.5 | 106.1 | 106.1 | 106.1 | 106.1 | 70.7 | 70.7 | 70.7 | 70.7 | 35.4 | 35.4 | 35.4 | 35.4 |
| O&M | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 |
| Fuel | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 |
| Administrative Expenses (M$) | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| Cost (M$) | 383.8 | 383.8 | 383.8 | 348.4 | 348.4 | 348.4 | 348.4 | 313.0 | 313.0 | 313.0 | 313.0 | 277.7 | 277.7 | 277.7 | 277.7 | 242.3 | 242.3 | 242.3 | 242.3 |
| With Profit (M$) | 416.2 | 416.2 | 416.2 | 377.9 | 377.9 | 377.9 | 377.9 | 339.5 | 339.5 | 339.5 | 339.5 | 301.2 | 301.2 | 301.2 | 301.2 | 262.8 | 262.8 | 262.8 | 262.8 |
| Cents/KWh | | | | | | | | | | | | | | | | | | | |
| Capital | 5.05 | 5.05 | 5.05 | 4.04 | 4.04 | 4.04 | 4.04 | 3.03 | 3.03 | 3.03 | 3.03 | 2.02 | 2.02 | 2.02 | 2.02 | 1.01 | 1.01 | 1.01 | 1.01 |
| O&M | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 |
| Fuel | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 |
| Administrative Expenses | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Total Cents/KWh | 10.95 | 10.95 | 10.95 | 9.94 | 9.94 | 9.94 | 9.94 | 8.93 | 8.93 | 8.93 | 8.93 | 7.92 | 7.92 | 7.92 | 7.92 | 6.92 | 6.92 | 6.92 | 6.92 |
| Total Cents/KWh with profit | 11.88 | 11.88 | 11.88 | 10.78 | 10.78 | 10.78 | 10.78 | 9.69 | 9.69 | 9.69 | 9.69 | 8.59 | 8.59 | 8.59 | 8.59 | 7.50 | 7.50 | 7.50 | 7.50 |

## SCENARIO 3

50 MW power plants using
low plant/wellfield costs and a
20% contingency

SCENARIO B3: 50 MW GEOTHERMAL PLANTS, LOW PLANT COSTS, FUEL OIL PRICE STABILIZES AT $45.00 PER BARREL IN 21ST YEAR OF PROJECT

| GEOTHERMAL POWER GENERATION YEAR | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Geothermal Development Timetable(MW) | | | 50 | | 50 | | 50 | | 50 | | 50 | | 50 | | 50 | | 50 | | 50 | | 50 |
| Total Net Capacity Development | | | 50 | 50 | 100 | 100 | 150 | 150 | 200 | 200 | 250 | 250 | 300 | 300 | 350 | 350 | 400 | 400 | 450 | 450 | 500 |
| Electricity Produced (1000MWh) | | | 350 | 350 | 701 | 701 | 1051 | 1051 | 1402 | 1402 | 1752 | 1752 | 2102 | 2102 | 2453 | 2453 | 2803 | 2803 | 3154 | 3154 | 3504 |
| COST FOR GEOTHERMAL POWER PROJECT | | | | | | | | | | | | | | | | | | | | | |
| Geothermal Plants (M$) | | | | | | | | | | | | | | | | | | | | | |
| Capital | 18.9 | 18.9 | 37.8 | 37.8 | 56.7 | 56.7 | 75.6 | 75.6 | 94.4 | 94.4 | 113.3 | 113.3 | 132.2 | 132.2 | 151.1 | 151.1 | 170.0 | 170.0 | 188.9 | 188.9 | 188.9 |
| Replacement Wells | | | | | 4.1 | 4.1 | 8.1 | 8.1 | 12.2 | 12.2 | 16.2 | 16.2 | 20.3 | 20.3 | 24.3 | 24.3 | 28.4 | 28.4 | 32.4 | 32.4 | 36.5 |
| O&M | | | 4.9 | 4.9 | 9.7 | 9.7 | 14.6 | 14.6 | 19.4 | 19.4 | 24.3 | 24.3 | 29.1 | 29.1 | 34.0 | 34.0 | 38.8 | 38.8 | 43.6 | 43.6 | 48.5 |
| Royalty Payments | | | | | | | | | | | 12.6 | 12.9 | 15.5 | 15.9 | 19.1 | 19.7 | 22.9 | 23.6 | 27.3 | 28.2 | 30.2 |
| Rent | 1.0 | 1.0 | 1.0 | 1.0 | 1.9 | 2.0 | 3.0 | 3.1 | 3.8 | 3.9 | 5.0 | 5.2 | 6.2 | 6.4 | 7.7 | 7.9 | 9.2 | 9.4 | 10.9 | 11.3 | 12.1 |
| Plant Replacement Fund | | | 121.0 | 0.0 | 107.1 | 0.0 | 102.8 | 0.0 | 93.7 | 0.0 | 84.6 | 0.0 | 75.5 | 0.0 | 66.4 | 0.0 | 57.3 | 0.0 | 48.2 | 0.0 | 39.1 |
| Cables and Facilities (M$) | | | | | | | | | | | | | | | | | | | | | |
| Capital | 40.3 | 40.3 | 40.3 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 |
| O&M | | | 1.0 | 1.0 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Administrative Expenses (M$) | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 |
| Cost (M$) | 60.2 | 60.2 | 205.9 | 112.7 | 249.0 | 142.0 | 273.7 | 171.0 | 293.3 | 199.7 | 325.0 | 241.7 | 348.6 | 273.0 | 372.5 | 306.9 | 396.5 | 340.2 | 421.5 | 374.5 | 425.3 |
| With profit (M$) | 65.3 | 65.3 | 223.3 | 122.2 | 270.1 | 154.0 | 296.0 | 185.5 | 318.1 | 216.6 | 353.4 | 262.2 | 378.1 | 296.9 | 404.0 | 332.9 | 430.0 | 368.9 | 457.1 | 406.1 | 461.3 |
| Cents/KWh (geothermal) | | | | | | | | | | | | | | | | | | | | | |
| Geothermal Plants | | | | | | | | | | | | | | | | | | | | | |
| Capital | 5.39 | 5.39 | 10.78 | 10.78 | 8.09 | 8.09 | 7.19 | 7.19 | 6.74 | 6.74 | 6.47 | 6.47 | 6.29 | 6.29 | 6.16 | 6.16 | 6.06 | 6.06 | 5.99 | 5.99 | 5.39 |
| Replacement Wells | | | | | 0.58 | 0.58 | 0.77 | 0.77 | 0.87 | 0.87 | 0.92 | 0.92 | 0.96 | 0.96 | 0.99 | 0.99 | 1.01 | 1.01 | 1.03 | 1.03 | 1.04 |
| O&M | | | 1.38 | 1.38 | 1.38 | 1.38 | 1.38 | 1.38 | 1.38 | 1.38 | 1.38 | 1.38 | 1.38 | 1.38 | 1.38 | 1.38 | 1.38 | 1.38 | 1.38 | 1.38 | 1.38 |
| Royalty Payments | | | | | | | | | | | 0.72 | 0.74 | 0.74 | 0.76 | 0.78 | 0.80 | 0.82 | 0.84 | 0.87 | 0.89 | 0.86 |
| Rent | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.28 | 0.29 | 0.29 | 0.27 | 0.28 | 0.29 | 0.30 | 0.29 | 0.30 | 0.31 | 0.32 | 0.33 | 0.34 | 0.35 | 0.36 | 0.34 |
| Plant Replacement Fund | | 0.00 | 34.52 | 0.00 | 15.28 | 0.00 | 9.78 | 0.00 | 6.68 | 0.00 | 4.83 | 0.00 | 3.59 | 0.00 | 2.71 | 0.00 | 2.04 | 0.00 | 1.53 | 0.00 | 1.12 |
| Cables and Facilities | | | | | | | | | | | | | | | | | | | | | |
| Capital | 11.50 | 11.50 | 11.50 | 19.41 | 9.70 | 9.70 | 6.47 | 6.47 | 4.85 | 4.85 | 3.88 | 3.88 | 3.23 | 3.23 | 2.77 | 2.77 | 2.43 | 2.43 | 2.16 | 2.16 | 1.94 |
| O&M | | | 0.29 | 0.29 | 0.21 | 0.21 | 0.14 | 0.14 | 0.11 | 0.11 | 0.09 | 0.09 | 0.07 | 0.07 | 0.06 | 0.06 | 0.05 | 0.05 | 0.05 | 0.05 | 0.04 |
| Administrative Expenses | 0.02 | 0.02 | 0.02 | 0.03 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Cents/KWh | 17.18 | 17.18 | 58.77 | 32.16 | 35.53 | 20.27 | 26.03 | 16.27 | 20.92 | 14.25 | 18.60 | 13.80 | 16.58 | 13.02 | 15.19 | 12.51 | 14.14 | 12.13 | 13.36 | 11.87 | 12.14 |
| Cents/KWh (with profit) | 18.64 | 18.64 | 63.74 | 34.88 | 38.54 | 21.98 | 28.24 | 17.64 | 22.69 | 15.45 | 20.17 | 14.96 | 17.99 | 14.12 | 16.47 | 13.57 | 15.34 | 13.16 | 14.50 | 12.88 | 13.16 |

SCENARIO B3 CONT.

| RESIDUAL FUEL OIL POWER GENERATION | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 |
| Oil Facility Development Timetable(MW) | | | | | 100 | | | | 100 | | | | 100 | | | | 100 | | | | 100 |
| Total Net Capacity Development | | | | | 100 | 100 | 100 | 100 | 200 | 200 | 200 | 200 | 300 | 300 | 300 | 300 | 400 | 400 | 400 | 400 | 500 |
| Oil Price ($ bbl) | | | | | 25.00 | 26.00 | 27.04 | 28.12 | 29.25 | 30.42 | 31.63 | 32.90 | 34.21 | 35.58 | 37.01 | 38.49 | 40.03 | 41.63 | 43.29 | 45.02 | 45.02 |
| Electricity Produced (1000MWh) | | | | | 701 | 701 | 701 | 701 | 1402 | 1402 | 1402 | 1402 | 2102 | 2102 | 2102 | 2102 | 2803 | 2803 | 2803 | 2803 | 3504 |
| Oil Consumed (M bbl) | | | | | 1.08 | 1.08 | 1.08 | 1.08 | 2.17 | 2.17 | 2.17 | 2.17 | 3.25 | 3.25 | 3.25 | 3.25 | 4.34 | 4.34 | 4.34 | 4.34 | 5.42 |
| COST FOR NEW OIL GENERATION FACILITIES | | | | | | | | | | | | | | | | | | | | | |
| Capital | 9.2 | 9.2 | 9.2 | 9.2 | 18.4 | 18.4 | 18.4 | 18.4 | 27.6 | 27.6 | 27.6 | 27.6 | 36.7 | 36.7 | 36.7 | 36.7 | 45.9 | 45.9 | 45.9 | 45.9 | 45.9 |
| O&M | | | | | 2.1 | 2.1 | 2.1 | 2.1 | 4.3 | 4.3 | 4.3 | 4.3 | 6.4 | 6.4 | 6.4 | 6.4 | 8.6 | 8.6 | 8.6 | 8.6 | 10.7 |
| Fuel | | | | | 27.1 | 28.2 | 29.3 | 30.5 | 63.4 | 66.0 | 68.6 | 71.4 | 111.3 | 115.8 | 120.4 | 125.2 | 173.7 | 180.6 | 187.8 | 195.4 | 244.2 |
| Administrative Expenses (M$) | | | | | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.6 | 0.6 | 0.8 |
| Cost (M$) | 9.2 | 9.2 | 9.2 | 9.2 | 47.8 | 48.9 | 50.0 | 51.2 | 95.6 | 98.1 | 100.8 | 103.5 | 155.0 | 159.4 | 164.0 | 168.9 | 228.8 | 235.7 | 242.9 | 250.4 | 301.6 |
| With Profit (M$) | 9.2 | 9.2 | 9.2 | 9.2 | 51.8 | 53.0 | 54.2 | 55.5 | 103.7 | 106.4 | 109.3 | 112.3 | 168.1 | 172.9 | 177.9 | 183.1 | 248.1 | 255.6 | 263.5 | 271.6 | 327.1 |
| Cents/KWh (oil) | | | | | | | | | | | | | | | | | | | | | |
| Capital | 1.31 | 1.31 | 1.31 | 1.31 | 2.62 | 2.62 | 2.62 | 2.62 | 1.97 | 1.97 | 1.97 | 1.97 | 1.75 | 1.75 | 1.75 | 1.75 | 1.64 | 1.64 | 1.64 | 1.64 | 1.31 |
| O&M | | | | | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 |
| Fuel | | | | | 3.87 | 4.02 | 4.19 | 4.35 | 4.53 | 4.71 | 4.90 | 5.09 | 5.30 | 5.51 | 5.73 | 5.96 | 6.20 | 6.44 | 6.70 | 6.97 | 6.97 |
| Administrative Expenses | | | | | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Total Cents/KWh | 1.31 | 1.31 | 1.31 | 1.31 | 6.82 | 6.97 | 7.13 | 7.30 | 6.82 | 7.00 | 7.19 | 7.39 | 7.37 | 7.58 | 7.80 | 8.03 | 8.16 | 8.41 | 8.67 | 8.93 | 8.61 |
| Total Cents/KWh with profit | 1.42 | 1.42 | 1.42 | 1.42 | 7.39 | 7.56 | 7.74 | 7.92 | 7.40 | 7.59 | 7.80 | 8.01 | 7.99 | 8.22 | 8.46 | 8.71 | 8.85 | 9.12 | 9.40 | 9.69 | 9.33 |

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| SOLAR/RESIDUAL FUEL OIL POWER GENERATION | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 |
| Solar/Oil Development Timetable(MW) | | | | | 100 | | | | 100 | | | | 100 | | | | 100 | | | | 100 |
| Total Net Capacity Development | | | | | 100 | 100 | 100 | 100 | 200 | 200 | 200 | 200 | 300 | 300 | 300 | 300 | 400 | 400 | 400 | 400 | 500 |
| Electricity Produced (1000MWh) | | | | | 701 | 701 | 701 | 701 | 1402 | 1402 | 1402 | 1402 | 2102 | 2102 | 2102 | 2102 | 2803 | 2803 | 2803 | 2803 | 3504 |
| Solar Produced Electricity (1000MWh) | | 301 | | | 210 | 210 | 210 | 210 | 420 | 420 | 420 | 420 | 631 | 631 | 631 | 631 | 841 | 841 | 841 | 841 | 1051 |
| Oil Price ($ bbl) | | | | | 25.00 | 26.00 | 27.04 | 28.12 | 29.25 | 30.42 | 31.63 | 32.90 | 34.21 | 35.58 | 37.01 | 38.49 | 40.03 | 41.63 | 43.29 | 45.02 | 45.02 |
| Oil Produced Electricity (1000MWh) | | 701 | | | 491 | 491 | 491 | 491 | 981 | 981 | 981 | 981 | 1472 | 1472 | 1472 | 1472 | 1962 | 1962 | 1962 | 1962 | 2453 |
| Oil Consumed (M bbl) | | | | | 0.76 | 0.76 | 0.76 | 0.76 | 1.52 | 1.52 | 1.52 | 1.52 | 2.28 | 2.28 | 2.28 | 2.28 | 3.04 | 3.04 | 3.04 | 3.04 | 3.80 |
| COST FOR SOLAR/OIL GENERATION FACILITIES | | | | | | | | | | | | | | | | | | | | | |
| Capital | 35.4 | 35.4 | 35.4 | 35.4 | 70.7 | 70.7 | 70.7 | 70.7 | 106.1 | 106.1 | 106.1 | 106.1 | 141.5 | 141.5 | 141.5 | 141.5 | 176.8 | 176.8 | 176.8 | 176.8 | 176.8 |
| O&M | | | | | 7.1 | 7.1 | 7.1 | 7.1 | 14.1 | 14.1 | 14.1 | 14.1 | 21.2 | 21.2 | 21.2 | 21.2 | 28.2 | 28.2 | 28.2 | 28.2 | 35.3 |
| Fuel | | | | | 19.0 | 19.7 | 20.5 | 21.4 | 44.4 | 46.2 | 48.0 | 50.0 | 77.9 | 81.1 | 84.3 | 87.7 | 121.6 | 126.4 | 131.5 | 136.7 | 170.9 |
| Administrative Expenses (M$) | | | | | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.6 | 0.6 | 0.8 |
| Cost (M$) | 35.4 | 35.4 | 35.4 | 35.4 | 96.9 | 97.7 | 98.5 | 99.3 | 164.9 | 166.7 | 168.5 | 170.5 | 241.0 | 244.1 | 247.4 | 250.7 | 327.2 | 332.1 | 337.1 | 342.4 | 383.8 |
| With Profit (M$) | 35.4 | 35.6 | 35.4 | 35.4 | 105.1 | 105.9 | 106.8 | 107.7 | 178.9 | 180.8 | 182.8 | 184.9 | 261.4 | 264.8 | 268.3 | 271.9 | 354.9 | 360.1 | 365.6 | 371.3 | 416.2 |
| Cents/KWh | | | | | | | | | | | | | | | | | | | | | |
| Capital | 5.05 | 5.05 | 5.05 | 5.05 | 10.09 | 10.09 | 10.09 | 10.09 | 7.57 | 7.57 | 7.57 | 7.57 | 6.73 | 6.73 | 6.73 | 6.73 | 6.31 | 6.31 | 6.31 | 6.31 | 5.05 |
| O&M | | | | | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 |
| Fuel | | | | | 2.71 | 2.82 | 2.93 | 3.05 | 3.17 | 3.30 | 3.43 | 3.56 | 3.71 | 3.86 | 4.01 | 4.17 | 4.34 | 4.51 | 4.69 | 4.88 | 4.88 |
| Administrative Expenses | | | | | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Total Cents/KWh | 5.05 | 5.05 | 5.05 | 5.05 | 13.83 | 13.94 | 14.05 | 14.17 | 11.77 | 11.89 | 12.02 | 12.16 | 11.46 | 11.61 | 11.77 | 11.93 | 11.67 | 11.85 | 12.03 | 12.21 | 10.95 |
| Total Cents/KWh with profit | 5.47 | 5.47 | 5.47 | 5.47 | 15.00 | 15.12 | 15.24 | 15.37 | 12.76 | 12.90 | 13.04 | 13.19 | 12.43 | 12.59 | 12.76 | 12.93 | 12.66 | 12.85 | 13.04 | 13.25 | 11.88 |

SCENARIO #3 CONT.

GEOTHERMAL POWER GENERATION

| YEAR | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Geothermal Development Timetable(MW) | | | | | | | | | | | | | | | | | | | |
| Total Net Capacity Development | 450 | 450 | 500 | 500 | 500 | 500 | 500 | 500 | 450 | 450 | 500 | 500 | 450 | 400 | 450 | 500 | 500 | 500 | 500 |
| Electricity Produced (1000MWh) | 3154 | 3154 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3154 | 3154 | 3504 | 3504 | 3154 | 2803 | 3154 | 3504 | 3504 | 3504 | 3504 |
| COST FOR GEOTHERMAL POWER PROJECT | | | | | | | | | | | | | | | | | | | |
| Geothermal Plants (M$) | | | | | | | | | | | | | | | | | | | |
| Capital | 170.0 | 170.0 | 170.0 | 151.1 | 151.1 | 132.2 | 132.2 | 113.3 | 113.3 | 94.4 | 94.4 | 94.4 | 75.6 | 37.8 | 37.8 | 37.8 | 37.8 | 18.9 | 18.9 |
| Replacement Wells | 36.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 |
| O&M | 48.5 | 48.5 | 48.5 | 48.5 | 48.5 | 48.5 | 48.5 | 48.5 | 48.5 | 48.5 | 48.5 | 48.5 | 48.5 | 48.5 | 48.5 | 48.5 | 48.5 | 48.5 | 48.5 |
| Royalty Payments | 27.1 | 27.1 | 30.2 | 29.2 | 29.2 | 29.2 | 29.2 | 28.3 | 25.5 | 25.5 | 28.3 | 27.4 | 24.7 | 21.9 | 24.7 | 26.5 | 26.5 | 26.5 | 26.5 |
| Rent | 10.9 | 10.9 | 12.1 | 11.7 | 11.7 | 11.7 | 11.7 | 11.3 | 10.2 | 10.2 | 11.3 | 11.0 | 9.9 | 8.8 | 9.9 | 10.6 | 10.6 | 10.6 | 10.6 |
| Plant Replacement Fund | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -44.4 | -46.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cables and Facilities (M$) | | | | | | | | | | | | | | | | | | | |
| Capital | 45.3 | 45.3 | 45.3 | 18.5 | 18.5 | 18.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| O&M | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Administrative Expenses (M$) | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| Cost (M$) | 340.4 | 344.4 | 348.7 | 301.6 | 301.6 | 282.7 | 219.9 | 198.1 | 240.1 | 221.2 | 225.2 | 223.9 | 201.2 | 159.6 | 163.4 | 166.0 | 166.0 | 147.1 | 147.1 |
| With profit (M$) | 369.2 | 373.6 | 378.1 | 327.1 | 327.1 | 306.6 | 238.5 | 214.8 | 260.4 | 239.9 | 244.2 | 242.8 | 218.2 | 173.1 | 177.2 | 180.0 | 180.0 | 159.5 | 159.5 |
| Cents/KWh (geothermal) | | | | | | | | | | | | | | | | | | | |
| Geothermal Plants | | | | | | | | | | | | | | | | | | | |
| Capital | 5.39 | 5.39 | 4.85 | 4.31 | 4.31 | 3.77 | 3.77 | 3.23 | 3.59 | 2.99 | 2.70 | 2.70 | 2.40 | 1.35 | 1.20 | 1.08 | 1.08 | 0.54 | 0.54 |
| Replacement Wells | 1.16 | 1.28 | 1.16 | 1.16 | 1.16 | 1.16 | 1.16 | 1.16 | 1.28 | 1.28 | 1.16 | 1.16 | 1.28 | 1.44 | 1.28 | 1.16 | 1.16 | 1.16 | 1.16 |
| O&M | 1.54 | 1.54 | 1.38 | 1.38 | 1.38 | 1.38 | 1.38 | 1.38 | 1.54 | 1.54 | 1.38 | 1.38 | 1.54 | 1.73 | 1.54 | 1.38 | 1.38 | 1.38 | 1.38 |
| Royalty Payments | 0.86 | 0.86 | 0.86 | 0.83 | 0.83 | 0.83 | 0.83 | 0.81 | 0.81 | 0.81 | 0.81 | 0.78 | 0.78 | 0.78 | 0.78 | 0.76 | 0.76 | 0.76 | 0.76 |
| Rent | 0.34 | 0.34 | 0.34 | 0.33 | 0.33 | 0.33 | 0.33 | 0.32 | 0.32 | 0.32 | 0.32 | 0.31 | 0.31 | 0.31 | 0.31 | 0.30 | 0.30 | 0.30 | 0.30 |
| Plant Replacement Fund | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -1.27 | -1.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Cables and Facilities | | | | | | | | | | | | | | | | | | | |
| Capital | 1.44 | 1.44 | 1.29 | 0.53 | 0.53 | 0.53 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| O&M | 0.05 | 0.05 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.05 | 0.05 | 0.04 | 0.04 | 0.05 | 0.05 | 0.05 | 0.04 | 0.04 | 0.04 | 0.04 |
| Administrative Expenses | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Cents/KWh | 10.79 | 10.92 | 9.95 | 8.61 | 8.61 | 8.07 | 6.27 | 5.65 | 7.61 | 7.02 | 6.43 | 6.39 | 6.38 | 5.69 | 5.18 | 4.74 | 4.74 | 4.20 | 4.20 |
| Cents/KWh (with profit) | 11.71 | 11.85 | 10.79 | 9.34 | 9.34 | 8.75 | 6.81 | 6.13 | 8.26 | 7.61 | 6.97 | 6.93 | 6.92 | 6.17 | 5.62 | 5.14 | 5.14 | 4.55 | 4.55 |

SCENARIO #3 CONT.

RESIDUAL FUEL OIL POWER GENERATION

| YEAR | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oil Facility Development Timetable(MW) | | | | | | | | | | | | | | | | | | | |
| Total Net Capacity Development | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| Oil Price ($ bbl) | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 |
| Electricity Produced (1000MWh) | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 |
| Oil Consumed (M bbl) | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 |
| COST FOR NEW OIL GENERATION FACILITIES | | | | | | | | | | | | | | | | | | | |
| Capital | 45.9 | 45.9 | 45.9 | 36.7 | 36.7 | 36.7 | 36.7 | 27.6 | 27.6 | 27.6 | 27.6 | 18.4 | 18.4 | 18.4 | 18.4 | 9.2 | 9.2 | 9.2 | 9.2 |
| O&M | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 |
| Fuel | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 |
| Administrative Expenses (M$) | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| Cost (M$) | 301.6 | 301.6 | 301.6 | 292.4 | 292.4 | 292.4 | 292.4 | 283.2 | 283.2 | 283.2 | 283.2 | 274.0 | 274.0 | 274.0 | 274.0 | 264.8 | 264.8 | 264.8 | 264.8 |
| With Profit (M$) | 327.1 | 327.1 | 327.1 | 317.1 | 317.1 | 317.1 | 317.1 | 307.1 | 307.1 | 307.1 | 307.1 | 297.2 | 297.2 | 297.2 | 297.2 | 287.2 | 287.2 | 287.2 | 287.2 |
| Cents/KWh (oil) | | | | | | | | | | | | | | | | | | | |
| Capital | 1.31 | 1.31 | 1.31 | 1.05 | 1.05 | 1.05 | 1.05 | 0.79 | 0.79 | 0.79 | 0.79 | 0.52 | 0.52 | 0.52 | 0.52 | 0.26 | 0.26 | 0.26 | 0.26 |
| O&M | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 |
| Fuel | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 |
| Administrative Expenses | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Total Cents/KWh | 8.61 | 8.61 | 8.61 | 8.34 | 8.34 | 8.34 | 8.34 | 8.08 | 8.08 | 8.08 | 8.08 | 7.82 | 7.82 | 7.82 | 7.82 | 7.56 | 7.56 | 7.56 | 7.56 |
| Total Cents/KWh with profit | 9.33 | 9.33 | 9.33 | 9.05 | 9.05 | 9.05 | 9.05 | 8.77 | 8.77 | 8.77 | 8.77 | 8.48 | 8.48 | 8.48 | 8.48 | 8.20 | 8.20 | 8.20 | 8.20 |

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SOLAR/RESIDUAL FUEL OIL POWER GENERATION

| YEAR | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Solar/Oil Development Timetable(MW) | | | | | | | | | | | | | | | | | | | |
| Total Net Capacity Development | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| Electricity Produced (1000MWh) | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 |
| Solar Produced Electricity (1000MWh) | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 |
| Oil Price ($ bbl) | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 |
| Oil Produced Electricity (1000MWh) | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 |
| Oil Consumed (M bbl) | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 |
| COST FOR SOLAR/OIL GENERATION FACILITIES | | | | | | | | | | | | | | | | | | | |
| Capital | 176.8 | 176.8 | 176.8 | 141.5 | 141.5 | 141.5 | 141.5 | 106.1 | 106.1 | 106.1 | 106.1 | 70.7 | 70.7 | 70.7 | 70.7 | 35.4 | 35.4 | 35.4 | 35.4 |
| O&M | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 |
| Fuel | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 |
| Administrative Expenses (M$) | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| Cost (M$) | 383.8 | 383.8 | 383.8 | 348.4 | 348.4 | 348.4 | 348.4 | 313.0 | 313.0 | 313.0 | 313.0 | 277.7 | 277.7 | 277.7 | 277.7 | 242.3 | 242.3 | 242.3 | 242.3 |
| With Profit (M$) | 416.2 | 416.2 | 416.2 | 377.9 | 377.9 | 377.9 | 377.9 | 339.5 | 339.5 | 339.5 | 339.5 | 301.2 | 301.2 | 301.2 | 301.2 | 262.8 | 262.8 | 262.8 | 262.8 |
| Cents/KWh | | | | | | | | | | | | | | | | | | | |
| Capital | 5.05 | 5.05 | 5.05 | 4.04 | 4.04 | 4.04 | 4.04 | 3.03 | 3.03 | 3.03 | 3.03 | 2.02 | 2.02 | 2.02 | 2.02 | 1.01 | 1.01 | 1.01 | 1.01 |
| O&M | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 |
| Fuel | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 |
| Administrative Expenses | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Total Cents/KWh | 10.95 | 10.95 | 10.95 | 9.94 | 9.94 | 9.94 | 9.94 | 8.93 | 8.93 | 8.93 | 8.93 | 7.92 | 7.92 | 7.92 | 7.92 | 6.92 | 6.92 | 6.92 | 6.92 |
| Total Cents/KWh with profit | 11.88 | 11.88 | 11.88 | 10.78 | 10.78 | 10.78 | 10.78 | 9.69 | 9.69 | 9.69 | 9.69 | 8.59 | 8.59 | 8.59 | 8.59 | 7.50 | 7.50 | 7.50 | 7.50 |

## SCENARIO 4

50 MW power plants using
high plant/wellfield costs and a
20% contingency

SCENARIO #4: 50 MW GEOTHERMAL PLANTS, HIGH PLANT COSTS, FUEL OIL PRICE STABILIZES AT $45.00 PER BARREL IN 21ST YEAR OF PROJECT

| GEOTHERMAL POWER GENERATION | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 |
| Geothermal Development Timetable(MW) | | | 50 | | 50 | | 50 | | 50 | | 50 | | 50 | | 50 | | 50 | | 50 | | 50 |
| Total Net Capacity Development | | | 50 | 50 | 100 | 100 | 150 | 150 | 200 | 200 | 250 | 250 | 300 | 300 | 350 | 350 | 400 | 400 | 450 | 450 | 500 |
| Electricity Produced (1000MWh) | | | 350 | 350 | 701 | 701 | 1051 | 1051 | 1402 | 1402 | 1752 | 1752 | 2102 | 2102 | 2453 | 2453 | 2803 | 2803 | 3154 | 3154 | 3504 |
| COST FOR GEOTHERMAL POWER PROJECT | | | | | | | | | | | | | | | | | | | | | |
| Geothermal Plants (M$) | | | | | | | | | | | | | | | | | | | | | |
| Capital | 22.9 | 22.9 | 45.9 | 45.9 | 68.8 | 68.8 | 91.8 | 91.8 | 114.7 | 114.7 | 137.6 | 137.6 | 160.6 | 160.6 | 183.5 | 183.5 | 206.5 | 206.5 | 229.4 | 229.4 | 229.4 |
| Replacement Wells | | | | | 5.4 | 5.4 | 10.8 | 10.8 | 16.2 | 16.2 | 21.6 | 21.6 | 27.0 | 27.0 | 32.4 | 32.4 | 37.8 | 37.8 | 43.2 | 43.2 | 48.6 |
| O&M | | | 8.4 | 8.4 | 16.8 | 16.8 | 25.1 | 25.1 | 33.5 | 33.5 | 41.9 | 41.9 | 50.3 | 50.3 | 58.7 | 58.7 | 67.0 | 67.0 | 75.4 | 75.4 | 83.8 |
| Royalty Payments | | | | | | | | | | | 12.6 | 12.9 | 15.5 | 15.9 | 19.1 | 19.7 | 22.9 | 23.6 | 27.3 | 28.2 | 30.2 |
| Rent | 1.0 | 1.0 | 1.0 | 1.0 | 1.9 | 2.0 | 3.0 | 3.1 | 3.8 | 3.9 | 5.0 | 5.2 | 6.2 | 6.4 | 7.7 | 7.9 | 9.2 | 9.4 | 10.9 | 11.3 | 12.1 |
| Plant Replacement Fund | | | 141.0 | 0.0 | 124.0 | 0.0 | 119.8 | 0.0 | 109.2 | 0.0 | 98.6 | 0.0 | 88.0 | 0.0 | 77.4 | 0.0 | 66.8 | 0.0 | 56.2 | 0.0 | 45.6 |
| Cables and Facilities (M$) | | | | | | | | | | | | | | | | | | | | | |
| Capital | 40.3 | 40.3 | 40.3 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 | 68.0 |
| O&M | | | 1.0 | 1.0 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Administrative Expenses (M$) | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 |
| Cost (M$) | 64.3 | 64.3 | 237.6 | 124.3 | 287.3 | 162.6 | 320.2 | 200.5 | 347.2 | 238.1 | 387.2 | 289.1 | 417.4 | 330.1 | 448.7 | 372.1 | 480.1 | 416.3 | 512.6 | 457.5 | 519.8 |
| With profit (M$) | 69.7 | 69.7 | 257.7 | 134.8 | 311.7 | 176.3 | 347.3 | 217.4 | 376.6 | 258.3 | 420.0 | 313.5 | 452.8 | 358.0 | 486.7 | 403.6 | 520.7 | 449.4 | 555.9 | 496.2 | 563.7 |
| Cents/KWh (geothermal) | | | | | | | | | | | | | | | | | | | | | |
| Geothermal Plants | | | | | | | | | | | | | | | | | | | | | |
| Capital | 6.55 | 6.55 | 13.09 | 13.09 | 9.82 | 9.82 | 8.73 | 8.73 | 8.18 | 8.18 | 7.86 | 7.86 | 7.64 | 7.64 | 7.48 | 7.48 | 7.37 | 7.37 | 7.27 | 7.27 | 6.55 |
| Replacement Wells | | | | | 0.77 | 0.77 | 1.03 | 1.03 | 1.16 | 1.16 | 1.23 | 1.23 | 1.28 | 1.28 | 1.32 | 1.32 | 1.35 | 1.35 | 1.37 | 1.37 | 1.39 |
| O&M | | | 2.39 | 2.39 | 2.39 | 2.39 | 2.39 | 2.39 | 2.39 | 2.39 | 2.39 | 2.39 | 2.39 | 2.39 | 2.39 | 2.39 | 2.39 | 2.39 | 2.39 | 2.39 | 2.39 |
| Royalty Payments | | | | | | | | | | | 0.72 | 0.74 | 0.74 | 0.76 | 0.78 | 0.80 | 0.82 | 0.84 | 0.87 | 0.89 | 0.86 |
| Rent | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.28 | 0.29 | 0.29 | 0.27 | 0.28 | 0.29 | 0.30 | 0.29 | 0.30 | 0.31 | 0.32 | 0.33 | 0.34 | 0.35 | 0.36 | 0.34 |
| Plant Replacement Fund | | 0.00 | 40.25 | 0.00 | 17.81 | 0.00 | 11.40 | 0.00 | 7.79 | 0.00 | 5.63 | 0.00 | 4.19 | 0.00 | 3.16 | 0.00 | 2.38 | 0.00 | 1.78 | 0.00 | 1.30 |
| Cables and Facilities | | | | | | | | | | | | | | | | | | | | | |
| Capital | 11.50 | 11.50 | 11.50 | 19.41 | 9.70 | 9.70 | 6.47 | 6.47 | 4.85 | 4.85 | 3.88 | 3.88 | 3.23 | 3.23 | 2.77 | 2.77 | 2.43 | 2.43 | 2.16 | 2.16 | 1.94 |
| O&M | | | 0.29 | 0.29 | 0.21 | 0.21 | 0.14 | 0.14 | 0.11 | 0.11 | 0.09 | 0.09 | 0.07 | 0.07 | 0.06 | 0.06 | 0.05 | 0.05 | 0.05 | 0.05 | 0.04 |
| Administrative Expenses | 0.02 | 0.02 | 0.02 | 0.03 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Cents/KWh | 18.34 | 18.34 | 67.81 | 35.48 | 41.00 | 23.20 | 30.46 | 19.07 | 24.77 | 16.99 | 22.10 | 16.50 | 19.86 | 15.70 | 18.29 | 15.17 | 17.13 | 14.78 | 16.25 | 14.51 | 14.83 |
| Cents/KWh (with profit) | 19.89 | 19.89 | 73.55 | 38.40 | 44.47 | 25.16 | 33.04 | 20.68 | 26.87 | 18.43 | 23.97 | 17.90 | 21.53 | 17.03 | 19.86 | 16.45 | 18.58 | 16.03 | 17.63 | 15.74 | 16.09 |

SCENARIO #4 CONT.

RESIDUAL FUEL OIL POWER GENERATION

| YEAR | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oil Facility Development Timetable(MW) | | | | | 100 | | | | 100 | | | | 100 | | | | 100 | | | | 100 |
| Total Net Capacity Development | | | | | 100 | 100 | 100 | 100 | 200 | 200 | 200 | 200 | 300 | 300 | 300 | 300 | 400 | 400 | 400 | 400 | 500 |
| Oil Price ($ bbl) | | | | | 25.00 | 26.00 | 27.04 | 28.12 | 29.25 | 30.42 | 31.63 | 32.90 | 34.21 | 35.58 | 37.01 | 38.49 | 40.03 | 41.63 | 43.29 | 45.02 | 45.02 |
| Electricity Produced (1000MWh) | | | | | 701 | 701 | 701 | 701 | 1402 | 1402 | 1402 | 1402 | 2102 | 2102 | 2102 | 2102 | 2803 | 2803 | 2803 | 2803 | 3504 |
| Oil Consumed (M bbl) | | | | | 1.08 | 1.08 | 1.08 | 1.08 | 2.17 | 2.17 | 2.17 | 2.17 | 3.25 | 3.25 | 3.25 | 3.25 | 4.34 | 4.34 | 4.34 | 4.34 | 5.42 |
| COST FOR NEW OIL GENERATION FACILITIES | | | | | | | | | | | | | | | | | | | | | |
| Capital | 9.2 | 9.2 | 9.2 | 9.2 | 18.4 | 18.4 | 18.4 | 18.4 | 27.6 | 27.6 | 27.6 | 27.6 | 36.7 | 36.7 | 36.7 | 36.7 | 45.9 | 45.9 | 45.9 | 45.9 | 45.9 |
| O&M | | | | | 2.1 | 2.1 | 2.1 | 2.1 | 4.3 | 4.3 | 4.3 | 4.3 | 6.4 | 6.4 | 6.4 | 6.4 | 8.6 | 8.6 | 8.6 | 8.6 | 10.7 |
| Fuel | | | | | 27.1 | 28.2 | 29.3 | 30.5 | 63.4 | 66.0 | 68.6 | 71.4 | 111.3 | 115.8 | 120.4 | 125.2 | 173.7 | 180.6 | 187.8 | 195.4 | 244.2 |
| Administrative Expenses (M$) | | | | | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.6 | 0.6 | 0.8 |
| Cost (M$) | 9.2 | 9.2 | 9.2 | 9.2 | 47.8 | 48.9 | 50.0 | 51.2 | 95.6 | 98.1 | 100.8 | 103.5 | 155.0 | 159.4 | 164.0 | 168.9 | 228.8 | 235.7 | 242.9 | 250.4 | 301.6 |
| With Profit (M$) | 9.2 | 9.2 | 9.2 | 9.2 | 51.8 | 53.0 | 54.2 | 55.5 | 103.7 | 106.4 | 109.3 | 112.3 | 168.1 | 172.9 | 177.9 | 183.1 | 248.1 | 255.6 | 263.5 | 271.6 | 327.1 |
| Cents/KWh (oil) | | | | | | | | | | | | | | | | | | | | | |
| Capital | 1.31 | 1.31 | 1.31 | 1.31 | 2.62 | 2.62 | 2.62 | 2.62 | 1.97 | 1.97 | 1.97 | 1.97 | 1.75 | 1.75 | 1.75 | 1.75 | 1.64 | 1.64 | 1.64 | 1.64 | 1.31 |
| O&M | | | | | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 |
| Fuel | | | | | 3.87 | 4.02 | 4.19 | 4.35 | 4.53 | 4.71 | 4.90 | 5.09 | 5.30 | 5.51 | 5.73 | 5.96 | 6.20 | 6.44 | 6.70 | 6.97 | 6.97 |
| Administrative Expenses | | | | | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Total Cents/KWh | 1.31 | 1.31 | 1.31 | 1.31 | 6.82 | 6.97 | 7.13 | 7.30 | 6.82 | 7.00 | 7.19 | 7.39 | 7.37 | 7.58 | 7.80 | 8.03 | 8.16 | 8.41 | 8.67 | 8.93 | 8.61 |
| Total Cents/KWh with profit | 1.42 | 1.42 | 1.42 | 1.42 | 7.39 | 7.56 | 7.74 | 7.92 | 7.40 | 7.59 | 7.80 | 8.01 | 7.99 | 8.22 | 8.46 | 8.71 | 8.85 | 9.12 | 9.40 | 9.69 | 9.33 |

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SOLAR/RESIDUAL FUEL OIL POWER GENERATION

| YEAR | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Solar/Oil Development Timetable(MW) | | | | | 100 | | | | 100 | | | | 100 | | | | 100 | | | | 100 |
| Total Net Capacity Development | | | | | 100 | 100 | 100 | 100 | 200 | 200 | 200 | 200 | 300 | 300 | 300 | 300 | 400 | 400 | 400 | 400 | 500 |
| Electricity Produced (1000MWh) | | | | | 701 | 701 | 701 | 701 | 1402 | 1402 | 1402 | 1402 | 2102 | 2102 | 2102 | 2102 | 2803 | 2803 | 2803 | 2803 | 3504 |
| Solar Produced Electricity (1000MWh) | | 30% | | | 210 | 210 | 210 | 210 | 420 | 420 | 420 | 420 | 631 | 631 | 631 | 631 | 841 | 841 | 841 | 841 | 1051 |
| Oil Price ($ bbl) | | | | | 25.00 | 26.00 | 27.04 | 28.12 | 29.25 | 30.42 | 31.63 | 32.90 | 34.21 | 35.58 | 37.01 | 38.49 | 40.03 | 41.63 | 43.29 | 45.02 | 45.02 |
| Oil Produced Electricity (1000MWh) | | 70% | | | 491 | 491 | 491 | 491 | 981 | 981 | 981 | 981 | 1472 | 1472 | 1472 | 1472 | 1962 | 1962 | 1962 | 1962 | 2453 |
| Oil Consumed (M bbl) | | | | | 0.76 | 0.76 | 0.76 | 0.76 | 1.52 | 1.52 | 1.52 | 1.52 | 2.28 | 2.28 | 2.28 | 2.28 | 3.04 | 3.04 | 3.04 | 3.04 | 3.80 |
| COST FOR SOLAR/OIL GENERATION FACILITIES | | | | | | | | | | | | | | | | | | | | | |
| Capital | 35.4 | 35.4 | 35.4 | 35.4 | 70.7 | 70.7 | 70.7 | 70.7 | 106.1 | 106.1 | 106.1 | 106.1 | 141.5 | 141.5 | 141.5 | 141.5 | 176.8 | 176.8 | 176.8 | 176.8 | 176.8 |
| O&M | | | | | 7.1 | 7.1 | 7.1 | 7.1 | 14.1 | 14.1 | 14.1 | 14.1 | 21.2 | 21.2 | 21.2 | 21.2 | 28.2 | 28.2 | 28.2 | 28.2 | 35.3 |
| Fuel | | | | | 19.0 | 19.7 | 20.5 | 21.4 | 44.4 | 46.2 | 48.0 | 50.0 | 77.9 | 81.1 | 84.3 | 87.7 | 121.6 | 126.4 | 131.5 | 136.7 | 170.9 |
| Administrative Expenses (M$) | | | | | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.6 | 0.6 | 0.8 |
| Cost (M$) | 35.4 | 35.4 | 35.4 | 35.4 | 96.9 | 97.7 | 98.5 | 99.3 | 164.9 | 166.7 | 168.5 | 170.5 | 241.0 | 244.3 | 247.4 | 250.7 | 327.2 | 332.1 | 337.1 | 342.4 | 383.8 |
| With Profit (M$) | 35.4 | 35.4 | 35.4 | 35.4 | 105.1 | 105.9 | 106.8 | 107.7 | 178.9 | 180.8 | 182.8 | 184.9 | 261.4 | 264.8 | 268.3 | 271.9 | 354.9 | 360.1 | 365.6 | 371.3 | 416.2 |
| Cents/KWh | | | | | | | | | | | | | | | | | | | | | |
| Capital | 5.05 | 5.05 | 5.05 | 5.05 | 10.09 | 10.09 | 10.09 | 10.09 | 7.57 | 7.57 | 7.57 | 7.57 | 6.73 | 6.73 | 6.73 | 6.73 | 6.31 | 6.31 | 6.31 | 6.31 | 5.05 |
| O&M | | | | | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 |
| Fuel | | | | | 2.71 | 2.82 | 2.93 | 3.05 | 3.17 | 3.30 | 3.43 | 3.56 | 3.71 | 3.86 | 4.01 | 4.17 | 4.34 | 4.51 | 4.69 | 4.88 | 4.88 |
| Administrative Expenses | | | | | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Total Cents/KWh | 5.05 | 5.05 | 5.05 | 5.05 | 13.83 | 13.94 | 14.05 | 14.17 | 11.77 | 11.89 | 12.02 | 12.16 | 11.46 | 11.61 | 11.77 | 11.93 | 11.67 | 11.85 | 12.03 | 12.21 | 10.95 |
| Total Cents/KWh with profit | 5.47 | 5.47 | 5.47 | 5.47 | 15.00 | 15.12 | 15.24 | 15.37 | 12.76 | 12.90 | 13.04 | 13.19 | 12.43 | 12.59 | 12.76 | 12.93 | 12.66 | 12.85 | 13.04 | 13.25 | 11.88 |

SCENARIO 04 CONT.

GEOTHERMAL POWER GENERATION

| YEAR | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Geothermal Development Timetable(MW) | | | | | | | | | | | | | | | | | | | |
| Total Net Capacity Development | 450 | 450 | 500 | 500 | 500 | 500 | 500 | 500 | 450 | 450 | 500 | 500 | 450 | 400 | 450 | 500 | 500 | 500 | 500 |
| Electricity Produced (1000MWh) | 3154 | 3154 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3154 | 3154 | 3504 | 3504 | 3154 | 2803 | 3154 | 3504 | 3504 | 3504 | 3504 |
| COST FOR GEOTHERMAL POWER PROJECT | | | | | | | | | | | | | | | | | | | |
| Geothermal Plants (M$) | | | | | | | | | | | | | | | | | | | |
| Capital | 206.5 | 206.5 | 206.5 | 183.5 | 183.5 | 160.6 | 160.6 | 137.6 | 137.6 | 114.7 | 114.7 | 114.7 | 91.8 | 45.9 | 45.9 | 45.9 | 45.9 | 22.9 | 22.9 |
| Replacement Wells | 48.6 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 | 54.0 |
| O&M | 83.8 | 83.8 | 83.8 | 83.8 | 83.8 | 83.8 | 83.8 | 83.8 | 83.8 | 83.8 | 83.8 | 83.8 | 83.8 | 83.8 | 83.8 | 83.8 | 83.8 | 83.8 | 83.8 |
| Royalty Payments | 27.1 | 27.1 | 30.2 | 29.2 | 29.2 | 29.2 | 29.2 | 28.3 | 25.5 | 25.5 | 28.3 | 27.4 | 24.7 | 21.9 | 24.7 | 26.5 | 26.5 | 26.5 | 26.5 |
| Rent | 10.9 | 10.9 | 12.1 | 11.7 | 11.7 | 11.7 | 11.7 | 11.3 | 10.2 | 10.2 | 11.3 | 11.0 | 9.9 | 8.8 | 9.9 | 10.6 | 10.6 | 10.6 | 10.6 |
| Plant Replacement Fund | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | -51.7 | -53.7 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cables and Facilities (M$) | | | | | | | | | | | | | | | | | | | |
| Capital | 45.3 | 45.3 | 45.3 | 18.5 | 18.5 | 18.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| O&M | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Administrative Expenses (M$) | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| Cost (M$) | 424.3 | 429.7 | 433.9 | 382.8 | 382.8 | 359.9 | 289.7 | 263.5 | 313.2 | 290.3 | 294.2 | 293.0 | 266.2 | 216.5 | 220.3 | 222.9 | 222.9 | 199.9 | 199.9 |
| With profit (M$) | 460.2 | 466.0 | 470.6 | 415.2 | 415.2 | 390.3 | 314.2 | 285.8 | 339.7 | 314.8 | 319.1 | 317.7 | 288.7 | 234.8 | 238.9 | 241.7 | 241.7 | 216.8 | 216.8 |
| Cents/KWh (geothermal) | | | | | | | | | | | | | | | | | | | |
| Geothermal Plants | | | | | | | | | | | | | | | | | | | |
| Capital | 6.55 | 6.55 | 5.89 | 5.24 | 5.24 | 4.58 | 4.58 | 3.93 | 4.36 | 3.64 | 3.27 | 3.27 | 2.91 | 1.64 | 1.45 | 1.31 | 1.31 | 0.65 | 0.65 |
| Replacement Wells | 1.54 | 1.71 | 1.54 | 1.54 | 1.54 | 1.54 | 1.54 | 1.54 | 1.71 | 1.71 | 1.54 | 1.54 | 1.71 | 1.93 | 1.71 | 1.54 | 1.54 | 1.54 | 1.54 |
| O&M | 2.66 | 2.66 | 2.39 | 2.39 | 2.39 | 2.39 | 2.39 | 2.39 | 2.66 | 2.66 | 2.39 | 2.39 | 2.66 | 2.99 | 2.66 | 2.39 | 2.39 | 2.39 | 2.39 |
| Royalty Payments | 0.86 | 0.86 | 0.86 | 0.83 | 0.83 | 0.83 | 0.83 | 0.81 | 0.81 | 0.81 | 0.81 | 0.78 | 0.78 | 0.78 | 0.78 | 0.76 | 0.76 | 0.76 | 0.76 |
| Rent | 0.34 | 0.34 | 0.34 | 0.33 | 0.33 | 0.33 | 0.33 | 0.32 | 0.32 | 0.32 | 0.32 | 0.31 | 0.31 | 0.31 | 0.31 | 0.30 | 0.30 | 0.30 | 0.30 |
| Plant Replacement Fund | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -1.48 | -1.53 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Cables and Facilities | | | | | | | | | | | | | | | | | | | |
| Capital | 1.44 | 1.44 | 1.29 | 0.53 | 0.53 | 0.53 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| O&M | 0.05 | 0.05 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.05 | 0.05 | 0.04 | 0.04 | 0.05 | 0.05 | 0.05 | 0.04 | 0.04 | 0.04 | 0.04 |
| Administrative Expenses | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Cents/KWh | 13.45 | 13.63 | 12.38 | 10.93 | 10.93 | 10.27 | 8.27 | 7.52 | 9.93 | 9.20 | 8.40 | 8.36 | 8.44 | 7.72 | 6.99 | 6.36 | 6.36 | 5.71 | 5.71 |
| Cents/KWh (with profit) | 14.59 | 14.78 | 13.43 | 11.85 | 11.85 | 11.14 | 8.97 | 8.16 | 10.77 | 9.98 | 9.11 | 9.07 | 9.15 | 8.38 | 7.58 | 6.90 | 6.90 | 6.19 | 6.19 |

SCENARIO #4 CONT.

RESIDUAL FUEL OIL POWER GENERATION

| YEAR | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oil Facility Development Timetable(MW) | | | | | | | | | | | | | | | | | | | |
| Total Net Capacity Development | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| Oil Price ($ bbl) | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 |
| Electricity Produced (1000MWh) | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 |
| Oil Consumed (M bbl) | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 | 5.42 |
| COST FOR NEW OIL GENERATION FACILITIES | | | | | | | | | | | | | | | | | | | |
| Capital | 45.9 | 45.9 | 45.9 | 36.7 | 36.7 | 36.7 | 36.7 | 27.6 | 27.6 | 27.6 | 27.6 | 18.4 | 18.4 | 18.4 | 18.4 | 9.2 | 9.2 | 9.2 | 9.2 |
| O&M | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 | 10.7 |
| Fuel | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 | 244.2 |
| Administrative Expenses (M$) | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| Cost (M$) | 301.6 | 301.6 | 301.6 | 292.4 | 292.4 | 292.4 | 292.4 | 283.2 | 283.2 | 283.2 | 283.2 | 274.0 | 274.0 | 274.0 | 274.0 | 264.8 | 264.8 | 264.8 | 264.8 |
| With Profit (M$) | 327.1 | 327.1 | 327.1 | 317.1 | 317.1 | 317.1 | 317.1 | 307.1 | 307.1 | 307.1 | 307.1 | 297.2 | 297.2 | 297.2 | 297.2 | 287.2 | 287.2 | 287.2 | 287.2 |
| Cents/KWh (oil) | | | | | | | | | | | | | | | | | | | |
| Capital | 1.31 | 1.31 | 1.31 | 1.05 | 1.05 | 1.05 | 1.05 | 0.79 | 0.79 | 0.79 | 0.79 | 0.52 | 0.52 | 0.52 | 0.52 | 0.26 | 0.26 | 0.26 | 0.26 |
| O&M | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 |
| Fuel | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 |
| Administrative Expenses | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Total Cents/KWh | 8.61 | 8.61 | 8.61 | 8.34 | 8.34 | 8.34 | 8.34 | 8.08 | 8.08 | 8.08 | 8.08 | 7.82 | 7.82 | 7.82 | 7.82 | 7.56 | 7.56 | 7.56 | 7.56 |
| Total Cents/KWh with profit | 9.33 | 9.33 | 9.33 | 9.05 | 9.05 | 9.05 | 9.05 | 8.77 | 8.77 | 8.77 | 8.77 | 8.48 | 8.48 | 8.48 | 8.48 | 8.20 | 8.20 | 8.20 | 8.20 |

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SOLAR/RESIDUAL FUEL OIL POWER GENERATION

| YEAR | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Solar/Oil Development Timetable(MW) | | | | | | | | | | | | | | | | | | | |
| Total Net Capacity Development | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| Electricity Produced (1000MWh) | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 | 3504 |
| Solar Produced Electricity (1000MWh) | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 | 1051 |
| Oil Price ($ bbl) | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 | 45.02 |
| Oil Produced Electricity (1000MWh) | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 | 2453 |
| Oil Consumed (M bbl) | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 | 3.80 |
| COST FOR SOLAR/OIL GENERATION FACILITIES | | | | | | | | | | | | | | | | | | | |
| Capital | 176.8 | 176.8 | 176.8 | 141.5 | 141.5 | 141.5 | 141.5 | 106.1 | 106.1 | 106.1 | 106.1 | 70.7 | 70.7 | 70.7 | 70.7 | 35.4 | 35.4 | 35.4 | 35.4 |
| O&M | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 | 35.3 |
| Fuel | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 | 170.9 |
| Administrative Expenses (M$) | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| Cost (M$) | 383.8 | 383.8 | 383.8 | 348.4 | 348.4 | 348.4 | 348.4 | 313.0 | 313.0 | 313.0 | 313.0 | 277.7 | 277.7 | 277.7 | 277.7 | 242.3 | 242.3 | 242.3 | 242.3 |
| With Profit (M$) | 416.2 | 416.2 | 416.2 | 377.9 | 377.9 | 377.9 | 377.9 | 339.5 | 339.5 | 339.5 | 339.5 | 301.2 | 301.2 | 301.2 | 301.2 | 262.8 | 262.8 | 262.8 | 262.8 |
| Cents/KWh | | | | | | | | | | | | | | | | | | | |
| Capital | 5.05 | 5.05 | 5.05 | 4.04 | 4.04 | 4.04 | 4.04 | 3.03 | 3.03 | 3.03 | 3.03 | 2.02 | 2.02 | 2.02 | 2.02 | 1.01 | 1.01 | 1.01 | 1.01 |
| O&M | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 | 1.01 |
| Fuel | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 | 4.88 |
| Administrative Expenses | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Total Cents/KWh | 10.95 | 10.95 | 10.95 | 9.94 | 9.94 | 9.94 | 9.94 | 8.93 | 8.93 | 8.93 | 8.93 | 7.92 | 7.92 | 7.92 | 7.92 | 6.92 | 6.92 | 6.92 | 6.92 |
| Total Cents/KWh with profit | 11.88 | 11.88 | 11.88 | 10.78 | 10.78 | 10.78 | 10.78 | 9.69 | 9.69 | 9.69 | 9.69 | 8.59 | 8.59 | 8.59 | 8.59 | 7.50 | 7.50 | 7.50 | 7.50 |

## SOLAR/RESIDUAL FUEL OIL POWER GENERATION cont'd

| | |
|---|---|
| O&M | The annual O&M costs of the power plants. (Northwest Power Planning Council estimate.) |
| Fuel | The annual fuel costs of the power plants (oil consumed times oil price). |
| Administrative Expenses | Based on similar costs per kWh found in Hawaiian Electric Industries, Inc. Annual Report. |
| Cost | Total annual project cost. |
| With Profit | Total annual project cost with 8% profit. Profit is calculated as a percent of annual costs based on Hawaiian Electric Industries, Inc., Annual Report. |

The second set of costs is in cents per kilowatt hour.

Tables 16, 17, 18, and 19 compare the costs of the three generation alternatives under 25 MW and 50 MW geothermal options with low and high plant/wellfield cost estimates using a 20% contingency for all three generation alternatives.

With 25 MW plants the cost of geothermal is between 1.9 and 2.3 times more costly than the oil generation option. With 50 MW plants, generation is 1.7 to 2.0 times as costly as oil. When compared to solar/oil, geothermal is 1.2 to 1.7 times as costly.

Table 20 shows the levels of rate increases that would have to be achieved to cover the cost of adding 500 MW of power generating capacity to the system over a 40 year period. With royalties paid to the state, rates per kWh could be expected to increase on average by 17% (50 MW low) to 30% (25 MW high) if the geothermal option is taken while a rate increase of 10% for oil and 17% for solar/oil could be expected.

Tables 21, 22, 23, and 24 compare the costs of the three generation alternatives using a 30% contingency for geothermal and 20% for oil and solar/oil. Table 25 shows the levels of rate increases with the 30% contingency level.

## Table 16

### 25 NET MW SUMMARY TABLE
### LOW GEOTHERMAL COSTS
### 20% CONTINGENCY

| | Geothermal | Solar/Oil | Oil |
|---|---|---|---|
| (1,000 MWh Produced) | 101,791 | 98,112<br>30% solar<br>70% oil | 98,112 |
| Total Oil Consumed (M bbl) | 0 | 106 | 152 |
| B$ Development Cost | 3.6 | 2.1 | 0.5 |
| B$ 40 Yr. Cumulative Cost | 12.1 | 10.6 | 8.6 |
| B$ NPV | 4.9 | 3.6 | 2.7 |
| Cost Ratio (oil = 1.0) | 1.85 | 1.37 | 1.00 |
| Cost Ratio (solar/oil = 1.0) | 1.36 | 1.00 | 0.73 |
| Levelized Cents/kWh | 11.87 | 10.81 | 8.73 |

## Table 17

### 25 NET MW SUMMARY TABLE
### HIGH GEOTHERMAL COSTS
### 20% CONTINGENCY

| | Geothermal | Solar/Oil | Oil |
|---|---|---|---|
| (1,000 MWh Produced) | 101,791 | 98,112<br>30% solar<br>70% oil | 98,112 |
| Total Oil Consumed (M bbl) | 0 | 106 | 152 |
| B$ Development Cost | 4.3 | 2.1 | 0.5 |
| B$ 40 Yr. Cumulative Cost | 15.0 | 10.6 | 8.6 |
| B$ NPV | 6.0 | 3.6 | 2.7 |
| Cost Ratio (oil = 1.0) | 2.25 | 1.37 | 1.00 |
| Cost Ratio (solar/oil = 1.0) | 1.65 | 1.00 | 0.73 |
| Levelized Cents/kWh | 14.71 | 10.81 | 8.73 |

## Table 18

### 50 NET MW SUMMARY TABLE
### LOW GEOTHERMAL COSTS
### 20% CONTINGENCY

| | Geothermal | Solar/Oil | Oil |
|---|---|---|---|
| (1,000 MWh Produced) | 98,813 | 98,112<br>30% solar<br>70% oil | 98,112 |
| Total Oil Consumed (M bbl) | 0 | 106 | 152 |
| B$ Development Cost | 3.4 | 2.1 | 0.5 |
| B$ 40 Yr. Cumulative Cost | 10.8 | 10.6 | 8.6 |
| B$ NPV | 4.5 | 3.6 | 2.7 |
| Cost Ratio (oil = 1.0) | 1.68 | 1.37 | 1.00 |
| Cost Ratio (solar/oil = 1.0) | 1.23 | 1.00 | 0.73 |
| Levelized Cents/kWh | 10.97 | 10.81 | 8.73 |

## Table 19

### 50 NET MW SUMMARY TABLE
### HIGH GEOTHERMAL COSTS
### 20% CONTINGENCY

| | Geothermal | Solar/Oil | Oil |
|---|---|---|---|
| (1,000 MWh Produced) | 98,813 | 98,112<br>30% solar<br>70% oil | 98,112 |
| Total Oil Consumed (M bbl) | 0 | 106 | 152 |
| B$ Development Cost | 4.0 | 2.1 | 0.5 |
| B$ 40 Yr. Cumulative Cost | 13.4 | 10.6 | 8.6 |
| B$ NPV | 5.4 | 3.6 | 2.7 |
| Cost Ratio (oil = 1.0) | 2.03 | 1.37 | 1.00 |
| Cost Ratio (solar/oil = 1.0) | 1.49 | 1.00 | 0.73 |
| Levelized Cents/kWh | 13.59 | 10.81 | 8.73 |

TABLE 20

AVERAGE KWH COST OF ELECTRICITY OVER 40 YEARS IF 500MW OF OTHER GENERATING CAPACITY IS ADDED TO EXISTING CAPACITY USING A 1990 ELECTRICITY USE AND COST ESTIMATE AS A BASE

(20% Contingency)

(2/1 Well Replacement)

| GEOTHERMAL LOW | EXISTING SYSTEM (1990) | GEOTHERMAL HIGH |
|---|---|---|
| 10,757,280,000 | Total kWh Capacity | 10,757,280,000 |
| 8,264,379,327 | With 23% Reserve | 8,264,379,327 |
| 613,974,852 | $ Operating Revenue | 613,974,852 |
| 8,264,379,327 | Annual kWh Sold | 8,264,379,327 |
| 7.43 | Average Cents/kWh | 7.43 |
| | ADDED CAPACITY (25MW PLANTS) (40 Years) | |
| 12,000,000,000 | $ Project Cost | 14,970,000,000 |
| 101,791,000,000 | kWh Sold | 101,791,000,000 |
| 11.87 | Average Cents/kWh With Royalty | 14.71 |
| | COMBINED CAPACITY (40 Years) | |
| 36,638,994,071 | $ Operating Revenue | 39,528,994,071 |
| 408,777,045,306 | kWh Sold | 408,777,045,306 |
| 8.96 | Average Cents/kWh | 9.67 |
| 1.53 | Cents/kWh Increase With Added Capacity | 2.24 |
| 20.6% | Cents/kWh % Increase With Added Capacity | 30.2% |

| GEOTHERMAL LOW | EXISTING SYSTEM (1990) | GEOTHERMAL HIGH |
|---|---|---|
| 10,757,280,000 | Total kWh Capacity | 10,757,280,000 |
| 8,264,379,327 | With 23% Reserve | 8,264,379,327 |
| 613,974,852 | $ Operating Revenue | 613,974,852 |
| 8,264,379,327 | Annual kWh Sold | 8,264,379,327 |
| 7.43 | Average Cents/kWh | 7.43 |
| | ADDED CAPACITY (50MW PLANTS) (40 Years) | |
| 10,040,000,000 | $ Project Cost | 13,430,000,000 |
| 98,013,000,000 | kWh Sold | 98,013,000,000 |
| 10.97 | Average Cents/kWh With Royalty | 13.59 |
| | COMBINED CAPACITY (40 Years) | |
| 35,398,994,071 | $ Operating Revenue | 37,988,994,071 |
| 406,409,169,409 | kWh Sold | 406,409,169,409 |
| 8.71 | Average Cents/kWh | 9.35 |
| 1.28 | Cents/kWh Increase With Added Capacity | 1.92 |
| 17.2% | Cents/kWh % Increase With Added Capacity | 25.8% |

| SOLAR/OIL | EXISTING SYSTEM (1990) | OIL |
|---|---|---|
| 10,757,280,000 | Total kWh Capacity | 10,757,280,000 |
| 8,264,379,327 | With 23% Reserve | 8,264,379,327 |
| 613,974,852 | $ Operating Revenue | 613,974,852 |
| 8,264,379,327 | Annual kWh Sold | 8,264,379,327 |
| 7.43 | Average Cents/kWh | 7.43 |
| | ADDED CAPACITY (100MW PLANTS) (40 Years) | |
| 10,610,000,000 | $ Project Cost | 8,570,000,000 |
| 98,112,000,000 | kWh Sold | 98,112,000,000 |
| 10.81 | Average Cents/kWh With Royalty | 8.73 |
| | COMBINED CAPACITY (40 Years) | |
| 35,168,994,071 | $ Operating Revenue | 33,128,994,071 |
| 405,950,619,709 | kWh Sold | 405,950,619,709 |
| 8.66 | Average Cents/kWh | 8.16 |
| 1.23 | Cents/kWh Increase With Added Capacity | 0.73 |
| 16.6% | Cents/kWh % Increase With Added Capacity | 9.8% |

Note: The 1990 average current rate per kilowatt hour is based on Hawaiian Electric Company, Inc. estimated 1989 operating revenues divided by annual kilowatt hours sold.

## Table 21

### 25 NET MW SUMMARY TABLE
### LOW GEOTHERMAL COSTS
### 30% CONTINGENCY

| | Geothermal | Solar/Oil | Oil |
|---|---|---|---|
| (1,000 MWh Produced) | 101,791 | 98,112<br>30% solar<br>70% oil | 98,112 |
| Total Oil Consumed (M bbl) | 0 | 106 | 152 |
| B$ Development Cost | 3.9 | 2.1 | 0.5 |
| B$ 40 Yr. Cumulative Cost | 12.7 | 10.6 | 8.6 |
| B$ NPV | 5.2 | 3.6 | 2.7 |
| Cost Ratio (oil = 1.0) | 1.95 | 1.37 | 1.00 |
| Cost Ratio (solar/oil = 1.0) | 1.42 | 1.00 | 0.73 |
| Levelized Cents/kWh | 12.46 | 10.81 | 8.73 |

## Table 22

### 25 NET MW SUMMARY TABLE
### HIGH GEOTHERMAL COSTS
### 30% CONTINGENCY

| | Geothermal | Solar/Oil | Oil |
|---|---|---|---|
| (1,000 MWh Produced) | 101,791 | 98,112<br>30% solar<br>70% oil | 98,112 |
| Total Oil Consumed (M bbl) | 0 | 106 | 152 |
| B$ Development Cost | 4.6 | 2.1 | 0.5 |
| B$ 40 Yr. Cumulative Cost | 15.7 | 10.6 | 8.6 |
| B$ NPV | 6.3 | 3.6 | 2.7 |
| Cost Ratio (oil = 1.0) | 2.36 | 1.37 | 1.00 |
| Cost Ratio (solar/oil = 1.0) | 1.73 | 1.00 | 0.73 |
| Levelized Cents/kWh | 15.43 | 10.81 | 8.73 |

Table 23

**50 NET MW SUMMARY TABLE
LOW GEOTHERMAL COSTS
30% CONTINGENCY**

| | Geothermal | Solar/Oil | Oil |
|---|---|---|---|
| (1,000 MWh Produced) | 98,813 | 98,112<br>30% solar<br>70% oil | 98,112 |
| Total Oil Consumed (M bbl) | 0 | 106 | 152 |
| B$ Development Cost | 3.6 | 2.1 | 0.5 |
| B$ 40 Yr. Cumulative Cost | 11.4 | 10.6 | 8.6 |
| B$ NPV | 4.7 | 3.6 | 2.7 |
| Cost Ratio (oil = 1.0) | 1.76 | 1.37 | 1.00 |
| Cost Ratio (solar/oil = 1.0) | 1.29 | 1.00 | 0.73 |
| Levelized Cents/kWh | 11.49 | 10.81 | 8.73 |

Table 24

**50 NET MW SUMMARY TABLE
HIGH GEOTHERMAL COSTS
30% CONTINGENCY**

| | Geothermal | Solar/Oil | Oil |
|---|---|---|---|
| (1,000 MWh Produced) | 98,813 | 98,112<br>30% solar<br>70% oil | 98,112 |
| Total Oil Consumed (M bbl) | 0 | 106 | 152 |
| B$ Development Cost | 4.3 | 2.1 | 0.5 |
| B$ 40 Yr. Cumulative Cost | 14.1 | 10.6 | 8.6 |
| B$ NPV | 5.7 | 3.6 | 2.7 |
| Cost Ratio (oil = 1.0) | 2.13 | 1.37 | 1.00 |
| Cost Ratio (solar/oil = 1.0) | 1.56 | 1.00 | 0.73 |
| Levelized Cents/kWh | 14.24 | 10.81 | 8.73 |

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### TABLE 25
**AVERAGE KWH COST OF ELECTRICITY OVER 40 YEARS IF 500MW OF OTHER GENERATING CAPACITY IS ADDED TO EXISTING CAPACITY USING A 1990 ELECTRICITY USE AND COST ESTIMATE AS A BASE**
**(30% Contingency)**
**(2/1 Well Replacement)**

| GEOTHERMAL LOW | | GEOTHERMAL HIGH |
|---|---|---|
| | **EXISTING SYSTEM (1990)** | |
| 10,757,280,000 | Total kWh Capacity | 10,757,280,000 |
| 8,264,379,327 | With 23% Reserve | 8,264,379,327 |
| 613,974,852 | $ Operating Revenue | 613,974,852 |
| 8,264,379,327 | Annual kWh Sold | 8,264,379,327 |
| 7.43 | Average Cents/kWh | 7.43 |
| **GEOTHERMAL LOW** | **ADDED CAPACITY (25MW PLANTS) (40 Years)** | **GEOTHERMAL HIGH** |
| 12,600,000,000 | $ Project Cost | 15,710,000,000 |
| 101,791,000,000 | kWh Sold | 101,791,000,000 |
| 12.46 | Average Cents/kWh With Royalty | 15.43 |
| | **COMBINED CAPACITY (40 Years)** | |
| 37,238,994,071 | $ Operating Revenue | 40,268,994,071 |
| 408,777,045,306 | kWh Sold | 408,777,045,306 |
| 9.11 | Average Cents/kWh | 9.85 |
| 1.68 | Cents/kWh Increase With Added Capacity | 2.42 |
| 22.6% | Cents/kWh % Increase With Added Capacity | 32.6% |

| GEOTHERMAL LOW | | GEOTHERMAL HIGH |
|---|---|---|
| | **EXISTING SYSTEM (1990)** | |
| 10,757,280,000 | Total kWh Capacity | 10,757,280,000 |
| 8,264,379,327 | With 23% Reserve | 8,264,379,327 |
| 613,974,852 | $ Operating Revenue | 613,974,852 |
| 8,264,379,327 | Annual kWh Sold | 8,264,379,327 |
| 7.43 | Average Cents/kWh | 7.43 |
| **GEOTHERMAL LOW** | **ADDED CAPACITY (50MW PLANTS) (40 Years)** | **GEOTHERMAL HIGH** |
| 11,350,000,000 | $ Project Cost | 14,070,000,000 |
| 98,813,000,000 | kWh Sold | 98,813,000,000 |
| 11.49 | Average Cents/kWh With Royalty | 14.24 |
| | **COMBINED CAPACITY (40 Years)** | |
| 35,908,994,071 | $ Operating Revenue | 38,628,994,071 |
| 406,489,169,409 | kWh Sold | 406,489,169,409 |
| 8.83 | Average Cents/kWh | 9.50 |
| 1.40 | Cents/kWh Increase With Added Capacity | 2.07 |
| 18.9% | Cents/kWh % Increase With Added Capacity | 27.9% |

| SOLAR/OIL | | OIL |
|---|---|---|
| | **EXISTING SYSTEM (1990)** | |
| 10,757,280,000 | Total kWh Capacity | 10,757,280,000 |
| 8,264,379,327 | With 23% Reserve | 8,264,379,327 |
| 613,974,852 | $ Operating Revenue | 613,974,852 |
| 8,264,379,327 | Annual kWh Sold | 8,264,379,327 |
| 7.43 | Average Cents/kWh | 7.43 |
| **SOLAR/OIL** | **ADDED CAPACITY (100MW PLANTS) (40 Years)** | **OIL** |
| 10,610,000,000 | $ Project Cost | 8,570,000,000 |
| 98,112,000,000 | kWh Sold | 98,112,000,000 |
| 10.81 | Average Cents/kWh With Royalty | 8.73 |
| | **COMBINED CAPACITY (40 Years)** | |
| 35,168,994,071 | $ Operating Revenue | 33,128,994,071 |
| 405,950,619,709 | kWh Sold | 405,950,619,709 |
| 8.66 | Average Cents/kWh | 8.16 |
| 1.23 | Cents/kWh Increase With Added Capacity | 0.73 |
| 16.6% | Cents/kWh % Increase With Added Capacity | 9.8% |

Note: The 1990 average current rate per kilowatt hour is based on Hawaiian Electric Company, Inc. estimated 1989 operating revenues divided by annual kilowatt hours sold.

# NEA - CONSERVATION AND SOLAR ENERGY

Conservation can be a key resource for meeting Hawaii's future electrical energy needs. Each megawatt of electricity conserved is one less megawatt that needs to be generated. Utilities all across the country are beginning to see conservation as a resource much less costly than the addition of new generating facilities. An article on energy appearing in *The Nation's Business*, February 1990 states:

> Experts say that universal adoption of standard conservation measures, such as insulation, recycling, and other practices, could cut U.S. energy consumption by as much as 20 percent. Even more energy could be saved, they add through broader application in business and industry of new technologies such as high-efficiency lighting, automatic controls, heat pumps, adjustable-speed drives, and thermal storage.
>
> A major boost for conservation is coming from utilities, which see programs to reduce demand as attractive alternatives to building more plants or buying electricity from independent producers. Financial incentives are available in many areas to business and individual users who agree to install energy-saving equipment or to cut back voluntarily on energy consumption.

Conservation no longer means "freezing in the dark" or "lowering your standard of living" as critics like to contend. It means being smart. It means being efficient, and that means it makes good business sense. The Northwest Power Planning Council, the organization in the Pacific Northwest responsible for energy planning defines conservation in the following way:[1]

> Conservation refers to the more efficient use of electricity--not curtailment--that results in the reduction of consumption. This means that less electricity is used to support the same level of amenity or production that existed before the conservation measure was implemented. Conservation resources are measures that enable residential and commercial buildings, appliances, and industrial and irrigation processes to use energy efficiently.

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1/ *1989 Supplement To The 1986 Northwest Conservation and Electric Power Plan*, Volume 1, Northwest Power Planning Council, 1989.

Conservation is also a uniquely flexible resource. Some conservation programs automatically match growth in electrical demand. Such is the case when new buildings are mandated by code to be energy-efficient. Each new building adds load to the electrical system, but can also save energy if it is better insulated than current practice. Thus, if the economy grows rapidly, the conservation resource expands quickly; but if the economy slows, the conservation resource automatically tracks the more slowly growing loads. Conservation can also be developed more quickly than generating resources when more electricity is required.

In other regions besides the Pacific Northwest conservation is being taken quite seriously by states and utilities. In New England the New England Electric System in partnership with the Conservation Law Foundation has begun a $65 million dollar per year energy conservation program.[1]

In California the California Energy Commission is writing and revising California's building and appliance standards. The Commission also forecasts energy supply and demand, approves or denies the need for new power plants, and reports to the Governor and Legislature on statewide energy use.[2]

The State of Hawaii faces the same problem as many of these other regions, whether to build more generating capacity or to become more efficient. The 500 MW geothermal project will cost the state and its ratepayers an immense amount of money. Conservation and increased efficiency will cost much less and involve much less risk. Table 26 shows the cost per kWh of some simple conservation measures and the effect they can have on reducing energy demand.

The 866 million kilowatt hours saved per year converts to about 123.6 annual megawatts of generating capacity (866 million ÷ 8,760 ÷ 0.8 ÷ 1,000). This is about 25% of the proposed 500 MW geothermal project. It consists of only five simple efficiency measures and costs an average of 3.0 cent per kWh.

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1/ *Energy Efficiency and Least Cost Planning: The Best Way To Save Money and Reduce Energy Use In Hawaii*, Robert J. Mowris, January 11, 1990. (See Appendix D in this report.)

2/ ibid

## Table 26

## CONSERVATION MEASURE COST/KWH[1]

| Efficiency Measure | Added Retail Cost | Annual Electricity Savings | Life | Cost of Conserved Electricity | Estimated Number Units | Statewide Savings Million |
|---|---|---|---|---|---|---|
| | $ | kWh/yr | Years | ¢/kWh | Thousands | Million kWh/yr |
| R-10 Water-Heater Blanket | 25 | 650 | 10 | 0.6 | 215 | 140 |
| Water-Saving Showerhead | 20 | 310 | 10 | 0.9 | 215 | 67 |
| Compact Fluorescent Lamp | 12 | 88 | 6.8 | 2.6 | 1,500 | 132 |
| Heat-Pump Water Heater | 650 | 2,280 | 10 | 4.0 | 215 | 490 |
| 1989 Best Mass- Produced Refrigerator | 60 | 125 | 15 | 4.6 | 292 | 36.5 |
| Average Cost of all Measures | | | | 3.0 | | |
| Total Savings | | | | | | 866 |

1/ "Energy Efficiency and Least Cost Planning: The Best Way To Save Money and Reduce Energy Use In Hawaii," Robert J. Mowris, January 11, 1990. (See Appendix D in this report.)

Table 27 compares the cost of these five conservation measures with the cost of adding 500 MW of geothermal, solar/oil, and oil fired generating capacity.

## Table 27

## COST COMPARISON OF CONSERVATION AND 500 MW ADDED GENERATING CAPACITY

| Type | Cents/kWh |
|---|---|
| Geothermal 20% Contingency | 10.97 - 14.71 |
| Geothermal 30% Contingency | 11.49 - 15.43 |
| Solar/Oil | 10.81 |
| Oil | 8.73 |
| Conservation | 3.0 |

The cost of conservation is by far the least expensive of the five options. Geothermal is the most expensive being 3.6 to 5.1 times as costly as conservation, while solar/oil is 3.6 times as costly, and oil 2.9 times the cost of conservation.

The conservation measures mentioned here are only a few of those available. Passive cooling building design, efficient air conditioning systems, waste heat recycling and co-generation can all contribute to lowering energy demand and cost. Conservation in concert with an aggressive solar energy program can have a considerable impact on energy use. In Florida, like Hawaii, cooling is a major user of electricity. Passive solar design in new homes can, according to the Florida Solar Energy Center,[1] can cut costs in half:

> In Florida, energy consumption in new homes can be reduced by 50% through passive cooling designs that add $2,000 to construction costs to typical homes, according to the Florida Solar Energy Center. Because an average home in Florida consumes 12,000 kWh/year, a $2,000 investment can save at least 6,000 kWh/year over an assumed 30-year life of the home. The cost of the conserved energy is about 1.1 cents/kWh (in constant dollars) compared with the average cost of electricity in Florida of 8 cents/kWh. The total investment can be recouped by savings on energy bills in less than 5 years.
>
> The designs that accomplish these savings include siting a new house facing north (for cooling), painting the house a light color, using light colored shingles or roofing, and installing attic radiant barriers, wall insulation, double pane windows with a reflective coating, and awnings.

And for existing homes:

> Increments of savings can also be achieved at low cost. A recent estimate by Lawrence Berkeley Laboratory shows that planting trees in urban areas is a cheap way to save air conditioning power. By planting 3 trees around a house to shade an air conditioner, 750 to 2,000 kWh/year of electricity could be saved at a cost of 0.2 to 1 cent/kWh (assuming $15 to $75 per tree plus watering costs).
>
> The cost of conserved energy from low-E window glazing is currently $4/MBtu, and, as the market matures, the cost is estimated to drop to $2/MBtu. (When these windows saturate the market early in the next century they will save energy equivalent to one-sixth of the output of the Alaska pipeline, or over 300,000 barrels of oil per day.)

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1/ *Power Surge, The Status and Near-Term Potential of Renewable Energy Technologies*, by Nancy Rader, for the Public Citizen Critical Mass Energy Project, May 1989.

And for both new and existing homes:

> The cost of energy saved over the 20-year life of an active solar domestic hot water system is about 4 to 5 cents/kWh. These systems can save from 40-70% of annual water heating costs.

The performance of solar energy systems is continually improving along with their appearance, reliability and cost. And they are becoming more and more competitive in the energy market place as Richard Balzhiser of the Electric Power Research Institute states in the previously mentioned article from *Nations Business*, February 1990:

> Solar energy could be an exception. Balzhiser says: "I think solar and particularly photovoltaic technology [in which sunlight is converted to electricity] is one [area] where we'll see continual progress scientifically."

Much of that progress is already here and readily available.

The conservation option and the solar option are two extremely important ways by which Hawaii can reduce its future energy demand. If these areas are explored and promoted with the same zeal as the geothermal project they hold the promise of even greater benefits with much less cost, risk, and public agitation. Hawaii should consider establishing a separate state government agency similar to the Northwest Power Planning Council and the California Energy Commission to examine all energy issues, needs and options and to actively develop and promote the most effective and least cost of them. The newly formed Hawaii Energy Coalition, a citizens group of planners and environmentalists, seems already headed in that direction.

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

## NEA - CONCLUSIONS

Based on this analysis the 500 MW geothermal project is the more costly and more risky of the available options. Its cumulative cost over 40 years in 1990 dollars is between $10.8 and $15.7 billion while solar/oil is $10.6 billion and conventional oil is $8.6 billion. In terms of net present values (the cumulative costs discounted back at a constant rate over 40 years to indicate how much you would have to invest today to achieve the same end in 40 years) the geothermal project is between $4.5 and $6.3 billion while solar/oil is $3.6 and oil is $2.7 billion. You would have to invest $0.9 to $2.7 billion more today in geothermal than solar/oil, and $1.8 to $3.6 billion more than oil to achieve the same benefit over the 40 year analysis period. Table 28 shows the annual cents per kWh increase over the estimated average current rate ratepayers would have to pay to cover the costs of the various generation options if they were incorporated into the overall generating system.

**Table 28**

**INCREASE OVER CURRENT RATES FOR VARIOUS GENERATION OPTIONS**
**(cents/kWh)**
**(Estimated 1990 Average Current Rate–7.43¢/kWh)**

| Type | Levelized Cost to Develop | Average Rate Increase Over Current Rates |
|---|---|---|
| Geothermal 30% Contingency | 11.49 - 15.43 | 1.40 - 2.42 (18.9% - 32.6%) |
| Geothermal 20% Contingency | 10.97 - 14.71 | 1.28 - 2.24 (17.2% - 30.2%) |
| Solar/Oil | 10.81 | 1.23 (16.6%) |
| Oil | 8.73 | 0.73 (9.8%) |

Ratepayers could annually pay more than three times as much for geothermal generated power as for oil generated power, and twice as much as for solar/oil generated power over their current rates.

In spite of the fact that geothermal costs are high NEA considers this analysis to be conservative. Recent revelations at The Geysers in California, the largest geothermal power production field in the world, indicate that the project is running out of steam and that billions of dollars may be lost as a result of this unexpected turn of events. This from the Oakland Tribune, November, 1989:[1]

> The world's largest geothermal-power producing field, The Geysers near Clear Lake, is running out of steam.
>
> To the astonishment of most geological experts, the steam that has powered $2 billion worth of nearly new power plants is declining sharply, and electrical output is dropping.
>
> Over the past two years, steam pressure has dropped 20 percent; some experts now predict it will be down by half by the end of the century.
>
> "This caught all of the geological experts by surprise," Charles Imbrecht, Chairman of the California Energy Commission, said last week.
>
> "We're taking it very, very seriously. There is several billion dollars' worth of investment in The Geysers," Imbrecht said.

The Geysers is the most studied geothermal reservoir in the world and the most developed, yet the predictions and theories concerning its energy capacity and potential are falling far short of expectations as the Oakland Tribune article goes on to state:

> Since oil and gas companies operate The Geysers steam wells, their officials are especially worried. Tom Sparks, a geothermal expert with Unocal Corp., the largest Geysers developer, said, "No one foresaw this happening.
>
> "We had thought there was a steady boiling mechanism 15 miles down, but that theory isn't working," Sparks said."

---

1/ *Geysers Failing, Billions of Dollars May Be Lost*, By Steven H. Heimoff, The Tribune, Oakland, California, November 5, 1989.

The owners and investors at The Geysers are now rethinking their position in light of recent events:

> Eastbay utility customers as well as investors have a stake in The Geysers.
>
> Geothermal power is cheap because is uses free steam and a simple generating system, if it peters out electricity from more expensive sources will be used and The Geysers idle power plants will still have to be paid off.
>
> Pacific Gas and Electric Co., which dominates the region with 19 power plants, has cancelled plans to build two more plants.

If this could happen at The Geysers, an area which has been studied so thoroughly, it could easily happen in Hawaii where the resource has been studied little by comparison.

Geothermal experts in California now feel that the original resource was overestimated and that too much steam is being withdrawn too quickly. Again, from the Oakland Tribune article:

> "Geothermal power is a depletable resource. It's been known that the field would decline." said Unocal spokesman Harry Bain.
>
> "Many of the plants were built in the middle 1980s" energy commission information officer Claudia Barker said. "They should have a 20- to 30-year lifespan." Instead, she noted, they may last half that long."
>
> Experts can only guess at the reasons for the shortfall, but most feel that too many plants are tapping a resource that is more limited than originally estimated.
>
> The Northern California Power Association, a consortium of municipal utility companies, testified before the State Energy Commission on Sept. 21 that the problem "is directly related to the mass withdrawal of steam."
>
> PG&E public relations spokesman Dick Davin agreed, saying, "There are too many straws in the soup.

The proposed Hawaii Geothermal Project will require 300 production wells (straws) at 4 MW per well and 400 production wells at 3 MW per well over the expected life of the project at 100% replacement. If, as is the case at The Geysers, the resource rapidly becomes depleted and the wells fail sooner than expected more wells will have to be sunk to try to replace the lost energy. At 200%

replacement the number of production wells could be between 450 and 600 over the expected life of the project. This large number of wells may easily overtap the reservoir.

For sake of continuity our analysis assumes that wellfield production will be adequate to maintain 500 net MW of output throughout the analysis period. In reality, however, this may not be the case and costs will rise accordingly. (See Appendix E for project costs at 200% well replacement.)

The extent and potential of the geothermal reservoir on Hawaii is unknown. For the most part it is being assumed that the 500 MW (600 MW gross) of energy is there and will be available for the long term. But according to testimony given in 1982 by Robert Decker, Scientist-in-Charge of the U.S. Geological Surveys' Hawaiian Volcano Observatory:[1]

> Any electrical power extraction from the Kahaule'a section of the east rift of Kilauea in excess of about 5 MW will not be replenished by new thermal power from the volcano and will probably deplete the geothermal resource.

The simple fact is the experts do not know how large the geothermal resource in Hawaii is or much energy can be extracted or at what rate before depletion occurs. Until this is known, rushing headlong into an incredibly costly 500 MW development project makes little economic sense, especially when other alternatives like conservation, solar, and improving existing efficiencies are available at far less cost. The geothermal project is being touted as a means of putting an end to Hawaii's energy problems when in reality it could be just the beginning of them.

If the state of Hawaii is really concerned about its long-term energy needs it should begin by looking at what an aggressive energy conservation and energy efficiency program can do about reducing energy demand, and then examine its least cost generation options. A single massive energy project is not the answer for the long run, because in the long-run survival does not necessarily go to the biggest or strongest, most often but to the smartest, most adaptable and most efficient users of resources.

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1/ *Energy Efficiency and Least Cost Planning: The Best Way To Save Money and Reduce Energy Use In Hawaii,* Robert J. Mowris, January 11, 1990, (see Appendix D).

# APPENDICES

# APPENDIX A

## WELL COSTS

WELL DRILLING COST SCENARIOS 3 MW PER WELL 1990 $

## WORST SCENARIO

### HIGH COST

Well Field Drilling Costs
- 3.00 Million Dollars Per Production Well
- 2.50 Million Dollars Per Injection Well
- 2.50 Million Dollars Per Unsuccessful Well
- 30 MW per Plant Well Field
- 3 MW per Well
- 27.5 Gross MW Plant Capacity Output
- 25.0 Net MW Plant Capacity Output
- 2.5 MW Plant Reserve Capacity
- 2.5 MW Wellfield Resesve Capacity
- 10 Production Wells
- 1.0 to 1.0 Production/Injection Well Ratio
- 10 Injection Wells
- 1.0 to 2.0 Production/Replacement Well Ratio
- 20 Production Replacement Wells
- 20 Injection Replacement Wells
- 1.0 to 1.0 Well Drilling Success Ratio
- 30 Unsuccessful Wells
- 90 Total Wells Required Over Life Of Plant
- 240.00 Million Dollars For Wells Required Over Life Of One Plant
- 20 Number Of Plants
- 4800.00 Million Dollars For Well Drilling Costs For 500MW Development
- 600 Total Production Wells
- 1200 Total Injection And Unsuccessful Wells
- 1800 Total Wells

### MID COST

Well Field Drilling Costs
- 2.50 Million Dollars Per Production Well
- 2.00 Million Dollars Per Injection Well
- 2.00 Million Dollars Per Unsuccessful Well
- 30 MW per Plant Well Field
- 3 MW per Well
- 27.5 Gross MW Plant Capacity Output
- 25.0 Net MW Plant Capacity Output
- 2.5 MW Plant Reserve Capacity
- 2.5 MW Wellfield Resesve Capacity
- 10 Production Wells
- 1.0 to 1.0 Production/Injection Well Ratio
- 10 Injection Wells
- 1.0 to 2.0 Production/Replacement Well Ratio
- 20 Production Replacement Wells
- 20 Injection Replacement Wells
- 1.0 to 1.0 Well Drilling Success Ratio
- 30 Unsuccessful Wells
- 90 Total Wells Required Over Life Of Plant
- 195.00 Million Dollars For Wells Required Over Life Of One Plant
- 20 Number Of Plants
- 3900.00 Million Dollars For Well Drilling Costs For 500MW Development
- 600 Total Production Wells
- 1200 Total Injection And Unsuccessful Wells
- 1800 Total Wells

### LOW COST

Well Field Drilling Costs
- 2.00 Million Dollars Per Production Well
- 1.50 Million Dollars Per Injection Well
- 1.50 Million Dollars Per Unsuccessful Well
- 30 MW per Plant Well Field
- 3 MW per Well
- 27.5 Gross MW Plant Capacity Output
- 25.0 Net MW Plant Capacity Output
- 2.5 MW Plant Reserve Capacity
- 2.5 MW Wellfield Resesve Capacity
- 10 Production Wells
- 1.0 to 1.0 Production/Injection Well Ratio
- 10 Injection Wells
- 1.0 to 2.0 Production/Replacement Well Ratio
- 20 Production Replacement Wells
- 20 Injection Replacement Wells
- 1.0 to 1.0 Well Drilling Success Ratio
- 30 Unsuccessful Wells
- 90 Total Wells Required Over Life Of Plant
- 150.00 Million Dollars For Wells Required Over Life Of One Plant
- 20 Number Of Plants
- 3000.00 Million Dollars For Well Drilling Costs For 500MW Development
- 600 Total Production Wells
- 1200 Total Injection And Unsuccessful Wells
- 1800 Total Wells

## MID SCENARIO

### HIGH COST

Well Field Drilling Costs
- 3.00 Million Dollars Per Production Well
- 2.50 Million Dollars Per Injection Well
- 2.50 Million Dollars Per Unsuccessful Well
- 30 MW per Plant Well Field
- 3 MW per Well
- 27.5 Gross MW Plant Capacity Output
- 25.0 Net MW Plant Capacity Output
- 2.5 MW Plant Reserve Capacity
- 2.5 MW Wellfield Resesve Capacity
- 10 Production Wells
- 2.0 to 1.0 Production/Injection Well Ratio
- 5 Injection Wells
- 1.0 to 1.0 Production/Replacement Well Ratio
- 10 Production Replacement Wells
- 5 Injection Replacement Wells
- 2.0 to 1.0 Well Drilling Success Ratio
- 10 Unsuccessful Wells
- 40 Total Wells Required Over Life Of Plant
- 110.00 Million Dollars For Wells Required Over Life Of One Plant
- 20 Number Of Plants
- 2200.00 Million Dollars For Well Drilling Costs For 500MW Development
- 400 Total Production Wells
- 400 Total Injection And Unsuccessful Wells
- 800 Total Wells

### MID COST

Well Field Drilling Costs
- 2.50 Million Dollars Per Production Well
- 2.00 Million Dollars Per Injection Well
- 2.00 Million Dollars Per Unsuccessful Well
- 30 MW per Plant Well Field
- 3 MW per Well
- 27.5 Gross MW Plant Capacity Output
- 25.0 Net MW Plant Capacity Output
- 2.5 MW Plant Reserve Capacity
- 2.5 MW Wellfield Resesve Capacity
- 10 Production Wells
- 2.0 to 1.0 Production/Injection Well Ratio
- 5 Injection Wells
- 1.0 to 1.0 Production/Replacement Well Ratio
- 10 Production Replacement Wells
- 5 Injection Replacement Wells
- 2.0 to 1.0 Well Drilling Success Ratio
- 10 Unsuccessful Wells
- 40 Total Wells Required Over Life Of Plant
- 90.00 Million Dollars For Wells Required Over Life Of One Plant
- 20 Number Of Plants
- 1800.00 Million Dollars For Well Drilling Costs For 500MW Development
- 400 Total Production Wells
- 400 Total Injection And Unsuccessful Wells
- 800 Total Wells

### LOW COST

Well Field Drilling Costs
- 2.00 Million Dollars Per Production Well
- 1.50 Million Dollars Per Injection Well
- 1.50 Million Dollars Per Unsuccessful Well
- 30 MW per Plant Well Field
- 3 MW per Well
- 27.5 Gross MW Plant Capacity Output
- 25.0 Net MW Plant Capacity Output
- 2.5 MW Plant Reserve Capacity
- 2.5 MW Wellfield Resesve Capacity
- 10 Production Wells
- 2.0 to 1.0 Production/Injection Well Ratio
- 5 Injection Wells
- 1.0 to 1.0 Production/Replacement Well Ratio
- 10 Production Replacement Wells
- 5 Injection Replacement Wells
- 2.0 to 1.0 Well Drilling Success Ratio
- 10 Unsuccessful Wells
- 40 Total Wells Required Over Life Of Plant
- 70.00 Million Dollars For Wells Required Over Life Of One Plant
- 20 Number Of Plants
- 1400.00 Million Dollars For Well Drilling Costs For 500MW Development
- 400 Total Production Wells
- 400 Total Injection And Unsuccessful Wells
- 800 Total Wells

BEST SCENARIO

HIGH COST

Well Field Drilling Costs

3.00 Million Dollars Per Production Well
2.50 Million Dollars Per Injection Well
2.50 Million Dollars Per Unsuccessful Well
30 MW per Plant Well Field
3 MW per Well
27.5 Gross MW Plant Capacity Output
25.0 Net MW Plant Capacity Output
2.5 MW Plant Reserve Capacity
2.5 MW Wellfield Resesve Capacity
10 Production Wells
3.0 to 1.0 Production/Injection Well Ratio
3 Injection Wells
2.0 to 1.0 Production/Replacement Well Ratio
5 Production Replacement Wells
2 Injection Replacement Wells
3.0 to 1.0 Well Drilling Success Ratio
5 Unsuccessful Wells
25 Total Wells Required Over Life Of Plant
70.00 Million Dollars For Wells Required Over Life Of One Plant
20 Number Of Plants
1400.00 Million Dollars For Well Drilling Costs For 500MW Development
300 Total Production Wells
200 Total Injection And Unsuccessful Wells
500 Total Wells

MID COST

Well Field Drilling Costs

2.50 Million Dollars Per Production Well
2.00 Million Dollars Per Injection Well
2.00 Million Dollars Per Unsuccessful Well
30 MW per Plant Well Field
3 MW per Well
27.5 Gross MW Plant Capacity Output
25.0 Net MW Plant Capacity Output
2.5 MW Plant Reserve Capacity
2.5 MW Wellfield Resesve Capacity
10 Production Wells
3.0 to 1.0 Production/Injection Well Ratio
3 Injection Wells
2.0 to 1.0 Production/Replacement Well Ratio
5 Production Replacement Wells
2 Injection Replacement Wells
3.0 to 1.0 Well Drilling Success Ratio
5 Unsuccessful Wells
25 Total Wells Required Over Life Of Plant
57.50 Million Dollars For Wells Required Over Life Of One Plant
20 Number Of Plants
1150.00 Million Dollars For Well Drilling Costs For 500MW Development
300 Total Production Wells
200 Total Injection And Unsuccessful Wells
500 Total Wells

LOW COST

Well Field Drilling Costs

2.00 Million Dollars Per Production Well
1.50 Million Dollars Per Injection Well
1.50 Million Dollars Per Unsuccessful Well
30 MW per Plant Well Field
3 MW per Well
27.5 Gross MW Plant Capacity Output
25.0 Net MW Plant Capacity Output
2.5 MW Plant Reserve Capacity
2.5 MW Wellfield Resesve Capacity
10 Production Wells
3.0 to 1.0 Production/Injection Well Ratio
3 Injection Wells
2.0 to 1.0 Production/Replacement Well Ratio
5 Production Replacement Wells
2 Injection Replacement Wells
3.0 to 1.0 Well Drilling Success Ratio
5 Unsuccessful Wells
25 Total Wells Required Over Life Of Plant
45.00 Million Dollars For Wells Required Over Life Of One Plant
20 Number Of Plants
900.00 Million Dollars For Well Drilling Costs For 500MW Development
300 Total Production Wells
200 Total Injection And Unsuccessful Wells
500 Total Wells

WELL DRILLING COST SCENARIOS 4 MW PER WELL 1990 $

## WORST SCENARIO

### HIGH COST

Well Field Drilling Costs

3.00 Million Dollars Per Production Well
2.50 Million Dollars Per Injection Well
2.50 Million Dollars Per Unsuccessful Well
30 MW per Plant Well Field
4 MW per Well
27.5 Gross MW Plant Capacity Output
25.0 Net MW Plant Capacity Output
2.5 MW Plant Reserve Capacity
2.5 MW Wellfield Resesve Capacity
8 Production Wells
1.0 to 1.0 Production/Injection Well Ratio
8 Injection Wells
1.0 to 2.0 Production/Replacement Well Ratio
15 Production Replacement Wells
15 Injection Replacement Wells
1.0 to 1.0 Well Drilling Success Ratio
23 Unsuccessful Wells
68 Total Wells Required Over Life Of Plant
180.00 Million Dollars For Wells Required Over Life Of One Plant
20 Number Of Plants
3600.00 Million Dollars For Well Drilling Costs For 500MW Development
450 Total Production Wells
900 Total Injection And Unsuccessful Wells
1350 Total Wells

### MID COST

Well Field Drilling Costs

2.50 Million Dollars Per Production Well
2.00 Million Dollars Per Injection Well
2.00 Million Dollars Per Unsuccessful Well
30 MW per Plant Well Field
4 MW per Well
27.5 Gross MW Plant Capacity Output
25.0 Net MW Plant Capacity Output
2.5 MW Plant Reserve Capacity
2.5 MW Wellfield Resesve Capacity
8 Production Wells
1.0 to 1.0 Production/Injection Well Ratio
8 Injection Wells
1.0 to 2.0 Production/Replacement Well Ratio
15 Production Replacement Wells
15 Injection Replacement Wells
1.0 to 1.0 Well Drilling Success Ratio
23 Unsuccessful Wells
68 Total Wells Required Over Life Of Plant
146.25 Million Dollars For Wells Required Over Life Of One Plant
20 Number Of Plants
2925.00 Million Dollars For Well Drilling Costs For 500MW Development
450 Total Production Wells
900 Total Injection And Unsuccessful Wells
1350 Total Wells

### LOW COST

Well Field Drilling Costs

2.00 Million Dollars Per Production Well
1.50 Million Dollars Per Injection Well
1.50 Million Dollars Per Unsuccessful Well
30 MW per Plant Well Field
4 MW per Well
27.5 Gross MW Plant Capacity Output
25.0 Net MW Plant Capacity Output
2.5 MW Plant Reserve Capacity
2.5 MW Wellfield Resesve Capacity
8 Production Wells
1.0 to 1.0 Production/Injection Well Ratio
8 Injection Wells
1.0 to 2.0 Production/Replacement Well Ratio
15 Production Replacement Wells
15 Injection Replacement Wells
1.0 to 1.0 Well Drilling Success Ratio
23 Unsuccessful Wells
68 Total Wells Required Over Life Of Plant
112.50 Million Dollars For Wells Required Over Life Of One Plant
20 Number Of Plants
2250.00 Million Dollars For Well Drilling Costs For 500MW Development
450 Total Production Wells
900 Total Injection And Unsuccessful Wells
1350 Total Wells

## MID SCENARIO

### HIGH COST

Well Field Drilling Costs

3.00 Million Dollars Per Production Well
2.50 Million Dollars Per Injection Well
2.50 Million Dollars Per Unsuccessful Well
30 MW per Plant Well Field
4 MW per Well
27.5 Gross MW Plant Capacity Output
25.0 Net MW Plant Capacity Output
2.5 MW Plant Reserve Capacity
2.5 MW Wellfield Resesve Capacity
8 Production Wells
2.0 to 1.0 Production/Injection Well Ratio
4 Injection Wells
1.0 to 1.0 Production/Replacement Well Ratio
8 Production Replacement Wells
4 Injection Replacement Wells
2.0 to 1.0 Well Drilling Success Ratio
8 Unsuccessful Wells
30 Total Wells Required Over Life Of Plant
82.50 Million Dollars For Wells Required Over Life Of One Plant
20 Number Of Plants
1650.00 Million Dollars For Well Drilling Costs For 500MW Development
300 Total Production Wells
300 Total Injection And Unsuccessful Wells
600 Total Wells

### MID COST

Well Field Drilling Costs

2.50 Million Dollars Per Production Well
2.00 Million Dollars Per Injection Well
2.00 Million Dollars Per Unsuccessful Well
30 MW per Plant Well Field
4 MW per Well
27.5 Gross MW Plant Capacity Output
25.0 Net MW Plant Capacity Output
2.5 MW Plant Reserve Capacity
2.5 MW Wellfield Resesve Capacity
8 Production Wells
2.0 to 1.0 Production/Injection Well Ratio
4 Injection Wells
1.0 to 1.0 Production/Replacement Well Ratio
8 Production Replacement Wells
4 Injection Replacement Wells
2.0 to 1.0 Well Drilling Success Ratio
8 Unsuccessful Wells
30 Total Wells Required Over Life Of Plant
67.50 Million Dollars For Wells Required Over Life Of One Plant
20 Number Of Plants
1350.00 Million Dollars For Well Drilling Costs For 500MW Development
300 Total Production Wells
300 Total Injection And Unsuccessful Wells
600 Total Wells

### LOW COST

Well Field Drilling Costs

2.00 Million Dollars Per Production Well
1.50 Million Dollars Per Injection Well
1.50 Million Dollars Per Unsuccessful Well
30 MW per Plant Well Field
4 MW per Well
27.5 Gross MW Plant Capacity Output
25.0 Net MW Plant Capacity Output
2.5 MW Plant Reserve Capacity
2.5 MW Wellfield Resesve Capacity
8 Production Wells
2.0 to 1.0 Production/Injection Well Ratio
4 Injection Wells
1.0 to 1.0 Production/Replacement Well Ratio
8 Production Replacement Wells
4 Injection Replacement Wells
2.0 to 1.0 Well Drilling Success Ratio
8 Unsuccessful Wells
30 Total Wells Required Over Life Of Plant
52.50 Million Dollars For Wells Required Over Life Of One Plant
20 Number Of Plants
1050.00 Million Dollars For Well Drilling Costs For 500MW Development
300 Total Production Wells
300 Total Injection And Unsuccessful Wells
600 Total Wells

BEST SCENARIO

### HIGH COST

Well Field Drilling Costs

3.00 Million Dollars Per Production Well
2.50 Million Dollars Per Injection Well
2.50 Million Dollars Per Unsuccessful Well
30 MW per Plant Well Field
4 MW per Well
27.5 Gross MW Plant Capacity Output
25.0 Net MW Plant Capacity Output
2.5 MW Plant Reserve Capacity
2.5 MW Wellfield Resesve Capacity
8 Production Wells
3.0 to 1.0 Production/Injection Well Ratio
3 Injection Wells
2.0 to 1.0 Production/Replacement Well Ratio
4 Production Replacement Wells
1 Injection Replacement Wells
3.0 to 1.0 Well Drilling Success Ratio
4 Unsuccessful Wells
19 Total Wells Required Over Life Of Plant
52.50 Million Dollars For Wells Required Over Life Of One Plant
20 Number Of Plants
1050.00 Million Dollars For Well Drilling Costs For 500MW Development
225 Total Production Wells
150 Total Injection And Unsuccessful Wells
375 Total Wells

### MID COST

Well Field Drilling Costs

2.50 Million Dollars Per Production Well
2.00 Million Dollars Per Injection Well
2.00 Million Dollars Per Unsuccessful Well
30 MW per Plant Well Field
4 MW per Well
27.5 Gross MW Plant Capacity Output
25.0 Net MW Plant Capacity Output
2.5 MW Plant Reserve Capacity
2.5 MW Wellfield Resesve Capacity
8 Production Wells
3.0 to 1.0 Production/Injection Well Ratio
3 Injection Wells
2.0 to 1.0 Production/Replacement Well Ratio
4 Production Replacement Wells
1 Injection Replacement Wells
3.0 to 1.0 Well Drilling Success Ratio
4 Unsuccessful Wells
19 Total Wells Required Over Life Of Plant
43.13 Million Dollars For Wells Required Over Life Of One Plant
20 Number Of Plants
862.50 Million Dollars For Well Drilling Costs For 500MW Development
225 Total Production Wells
150 Total Injection And Unsuccessful Wells
375 Total Wells

### LOW COST

Well Field Drilling Costs

2.00 Million Dollars Per Production Well
1.50 Million Dollars Per Injection Well
1.50 Million Dollars Per Unsuccessful Well
30 MW per Plant Well Field
4 MW per Well
27.5 Gross MW Plant Capacity Output
25.0 Net MW Plant Capacity Output
2.5 MW Plant Reserve Capacity
2.5 MW Wellfield Resesve Capacity
8 Production Wells
3.0 to 1.0 Production/Injection Well Ratio
3 Injection Wells
2.0 to 1.0 Production/Replacement Well Ratio
4 Production Replacement Wells
1 Injection Replacement Wells
3.0 to 1.0 Well Drilling Success Ratio
4 Unsuccessful Wells
19 Total Wells Required Over Life Of Plant
33.75 Million Dollars For Wells Required Over Life Of One Plant
20 Number Of Plants
675.00 Million Dollars For Well Drilling Costs For 500MW Development
225 Total Production Wells
150 Total Injection And Unsuccessful Wells
375 Total Wells

# APPENDIX B

## PLANT COSTS

HAWAII GEOTHERMAL PROJECT COST ESTIMATE SHEET
25 NET MEGAWATT PLANT

LOW ESTIMATE--1990 DOLLARS

| | |
|---|---|
| RESOURCE TEMPERATURE: | 350 DEG C |
| PLANT CAPACITY: | 27.5 MW (4 MW/WELL) |
| TECHNOLOGY (SF,DF,B): | SF |
| TERRAIN LABOR FACTOR (Y=1,N=0): | 0 |
| TERRAIN SITE PREP (Y=1,N=0): | 1 |
| CONSTRUCTION CAMP (Y=1,N=0): | 1 |
| PLANT O & M: LOW,PROB.,or HIGH | P |
| PRODUCTION EQUIPMENT: L,P,H | P |
| INJECTION EQUIPMENT: L,P,H | P |
| WELL O & M: L,P,H | P |
| ELECTRICITY COST: | 13 cents/kWh |
| TRANSMISSION LINE DISTANCE: | 10 miles |
| REMAINING ASSESSMENT WORK: | 2.50 million 1990 $ |
| PERMITS/LICENSES: | 0.75 million 1990 $ |
| # PRODUCTION WELLS: | 8 |
| # INJECTION WELLS: | 4 |
| # REPLACEMENT WELLS: | 12 |
| # UNSUCCESSFUL WELLS: | 8 |

WELLFIELD CAPITAL COSTS

| | |
|---|---|
| PRODUCTION EQUIPMENT | 4.90 |
| INJECTION EQUIPMENT | 4.78 |
| TERRAIN LABOR ADJUSTMENT | 0.00 |
| TERRAIN SITE PREP.ADJUSTMENT | 0.19 |
| CONSTRUCTION CAMP | 1.06 |
| S U B T O T A L (WELLFIELD) | 10.93 million 1984 $ |
| S U B T O T A L (WELLFIELD) | 11.91 million 1990 $ |
| WELLFIELD COST/MW | 0.43 million 1990 $ |
| WELLFIELD COST/KW | 433 1990 $ |
| WELL & WELLFIELD O & M COSTS | 0.74 million 1984 $ |
| WELL & WELLFIELD O & M COSTS | 0.80 million 1990 $ |

POWER PLANT CAPITAL COSTS

| | |
|---|---|
| POWER PLANT | 24.34 |
| H2S ABATEMENT | 6.46 |
| TERRAIN LABOR ADJUSTMENT | 0.00 |
| TERRAIN SITE PREP. ADJUSTMENT | 0.62 |
| CONSTRUCTION CAMP | 2.85 |
| S U B T O T A L (POWER PLANT) | 34.27 million 1984 $ |
| S U B T O T A L (POWER PLANT) | 37.32 million 1990 $ |
| POWER PLANT COST/MW | 1.36 million 1990 $ |
| POWER PLANT COST/KW | 1357 1990 $ |
| PLANT O & M COSTS | 1.82 million 1984 $ |
| PLANT O & M COSTS | 1.98 million 1990 $ |
| | |
| PLANT/WELLFIELD CAPITAL COSTS | 49.23 million 1990 $ |
| PLANT/WELLFIELD COST/MW | 1.79 million 1990 $ |
| PLANT/WELLFIELD COST/KW | 1790 1990 $ |
| WELL DRILLING COSTS | 33.75 million 1990 $ |
| TRANSMISSION LINE COSTS | 3.60 million 1990 $ |
| TOTAL CAPITAL COSTS | 86.58 million 1990 $ |
| | |
| TOTAL O & M COSTS | 2.79 million 1990 $ |
| | |
| PLANT/WELL BASE COST: | 86.58 |
| OTHER COSTS: | 3.25 million 1990 $ |
| TOTAL PLANT/WELL BASE COST: | 89.83 million 1990 $ |
| WITH 20% CONTINGENCY: | 107.79 |
| NUMBER OF POWER PLANTS NEEDED: | 20.00 |
| TOTAL COST FOR POWER PLANTS: | 2155.81 million 1990 $ |
| SUBMARINE CABLE COSTS: | 374.56 million 1990 $ |
| OVERHEAD TRANSMISSION COSTS: | 298.94 million 1990 $ |
| | |
| TOTAL PROJECT CAPITAL COST: | 2829.31 million 1990 $ |
| WITH REPLACEMENT WELLS: | 3639.31 million 1990 $ |
| | |
| ANNUAL PROJECT O & M COST: | 55.71 million 1990 $ |

HAWAII GEOTHERMAL PROJECT COST ESTIMATE SHEET
25 NET MEGAWATT PLANT

HIGH ESTIMATE--1990 DOLLARS

| | |
|---|---|
| RESOURCE TEMPERATURE: | 350 DEG C |
| PLANT CAPACITY: | 27.5 MW (3 MW/WELL) |
| TECHNOLOGY (SF,DF,B): | SF |
| TERRAIN LABOR FACTOR (Y=1,N=0): | 0 |
| TERRAIN SITE PREP (Y=1,N=0): | 1 |
| CONSTRUCTION CAMP (Y=1,N=0): | 1 |
| PLANT O & M: LOW,PROB.,or HIGH | H |
| PRODUCTION EQUIPMENT: L,P,H | H |
| INJECTION EQUIPMENT: L,P,H | H |
| WELL O & M: L,P,H | H |
| ELECTRICITY COST: | 13 cents/kWh |
| TRANSMISSION LINE DISTANCE: | 10 miles |
| REMAINING ASSESSMENT WORK: | 3.00 million 1990 $ |
| PERMITS/LICENSES: | 1.00 million 1990 $ |
| # PRODUCTION WELLS: | 10 |
| # INJECTION WELLS: | 5 |
| # REPLACEMENT WELLS: | 15 |
| # UNSUCCESSFUL WELLS: | 10 |

WELLFIELD CAPITAL COSTS

| | |
|---|---|
| PRODUCTION EQUIPMENT | 6.13 |
| INJECTION EQUIPMENT | 5.72 |
| TERRAIN LABOR ADJUSTMENT | 0.00 |
| TERRAIN SITE PREP.ADJUSTMENT | 0.24 |
| CONSTRUCTION CAMP | 1.06 |
| S U B T O T A L (WELLFIELD) | 13.15 million 1984 $ |
| S U B T O T A L (WELLFIELD) | 14.32 million 1990 $ |
| WELLFIELD COST/MW | 0.52 million 1990 $ |
| WELLFIELD COST/KW | 521 1990 $ |
| WELL & WELLFIELD O & M COSTS | 1.10 million 1984 $ |
| WELL & WELLFIELD O & M COSTS | 1.19 million 1990 $ |

POWER PLANT CAPITAL COSTS

| | |
|---|---|
| POWER PLANT | 24.34 |
| H2S ABATEMENT | 9.70 |
| TERRAIN LABOR ADJUSTMENT | 0.00 |
| TERRAIN SITE PREP. ADJUSTMENT | 0.68 |
| CONSTRUCTION CAMP | 2.85 |
| S U B T O T A L (POWER PLANT) | 37.57 million 1984 $ |
| S U B T O T A L (POWER PLANT) | 40.91 million 1990 $ |
| POWER PLANT COST/MW | 1.49 million 1990 $ |
| POWER PLANT COST/KW | 1488 1990 $ |
| PLANT O & M COSTS | 3.32 million 1984 $ |
| PLANT O & M COSTS | 3.62 million 1990 $ |
| | |
| PLANT/WELLFIELD CAPITAL COSTS | 55.23 million 1990 $ |
| PLANT/WELLFIELD COST/MW | 2.01 million 1990 $ |
| PLANT/WELLFIELD COST/KW | 2008 1990 $ |
| WELL DRILLING COSTS | 45.00 million 1990 $ |
| TRANSMISSION LINE COSTS | 3.60 million 1990 $ |
| TOTAL CAPITAL COSTS | 103.83 million 1990 $ |
| | |
| TOTAL O & M COSTS | 4.81 million 1990 $ |
| | |
| POWER PLANT BASE COST: | 103.83 |
| OTHER COSTS: | 4.00 million 1990 $ |
| TOTAL POWER PLANT BASE COST: | 107.83 million 1990 $ |
| WITH 20% CONTINGENCY: | 129.40 |
| NUMBER OF POWER PLANTS NEEDED: | 20.00 |
| TOTAL COST FOR POWER PLANTS: | 2587.98 million 1990 $ |
| SUBMARINE CABLE COSTS: | 374.56 million 1990 $ |
| OVERHEAD TRANSMISSION COSTS: | 298.94 million 1990 $ |
| | |
| TOTAL PROJECT CAPITAL COST: | 3261.48 million 1990 $ |
| WITH REPLACEMENT WELLS: | 4301.48 million 1990 $ |
| | |
| ANNUAL PROJECT O & M COST: | 96.29 million 1990 $ |

HAWAII GEOTHERMAL PROJECT COST ESTIMATE SHEET
25 NET MEGAWATT PLANT

LOW ESTIMATE--1990 DOLLARS

| | |
|---|---|
| RESOURCE TEMPERATURE: | 350 DEG C |
| PLANT CAPACITY: | 27.5 MW (4 MW/WELL) |
| TECHNOLOGY (SF,DF,B): | SF |
| TERRAIN LABOR FACTOR (Y=1,N=0): | 0 |
| TERRAIN SITE PREP (Y=1,N=0): | 1 |
| CONSTRUCTION CAMP (Y=1,N=0): | 1 |
| PLANT O & M: LOW,PROB.,or HIGH | P |
| PRODUCTION EQUIPMENT: L,P,H | P |
| INJECTION EQUIPMENT: L,P,H | P |
| WELL O & M: L,P,H | P |
| ELECTRICITY COST: | 13 cents/kWh |
| TRANSMISSION LINE DISTANCE: | 10 miles |
| REMAINING ASSESSMENT WORK: | 2.50 million 1990 $ |
| PERMITS/LICENSES: | 0.75 million 1990 $ |
| # PRODUCTION WELLS: | 8 |
| # INJECTION WELLS: | 4 |
| # REPLACEMENT WELLS: | 12 |
| # UNSUCCESSFUL WELLS: | 8 |

WELLFIELD CAPITAL COSTS

| | |
|---|---|
| PRODUCTION EQUIPMENT | 4.90 |
| INJECTION EQUIPMENT | 4.78 |
| TERRAIN LABOR ADJUSTMENT | 0.00 |
| TERRAIN SITE PREP.ADJUSTMENT | 0.19 |
| CONSTRUCTION CAMP | 1.06 |
| S U B T O T A L (WELLFIELD) | 10.93 million 1984 $ |
| S U B T O T A L (WELLFIELD) | 11.91 million 1990 $ |
| WELLFIELD COST/MW | 0.43 million 1990 $ |
| WELLFIELD COST/KW | 433 1990 $ |
| WELL & WELLFIELD O & M COSTS | 0.74 million 1984 $ |
| WELL & WELLFIELD O & M COSTS | 0.80 million 1990 $ |

POWER PLANT CAPITAL COSTS

| | |
|---|---|
| POWER PLANT | 24.34 |
| H2S ABATEMENT | 6.46 |
| TERRAIN LABOR ADJUSTMENT | 0.00 |
| TERRAIN SITE PREP. ADJUSTMENT | 0.62 |
| CONSTRUCTION CAMP | 2.85 |
| S U B T O T A L (POWER PLANT) | 34.27 million 1984 $ |
| S U B T O T A L (POWER PLANT) | 37.32 million 1990 $ |
| POWER PLANT COST/MW | 1.36 million 1990 $ |
| POWER PLANT COST/KW | 1357 1990 $ |
| PLANT O & M COSTS | 1.82 million 1984 $ |
| PLANT O & M COSTS | 1.98 million 1990 $ |
| PLANT/WELLFIELD CAPITAL COSTS | 49.23 million 1990 $ |
| PLANT/WELLFIELD COST/MW | 1.79 million 1990 $ |
| PLANT/WELLFIELD COST/KW | 1790 1990 $ |
| WELL DRILLING COSTS | 33.75 million 1990 $ |
| TRANSMISSION LINE COSTS | 3.60 million 1990 $ |
| TOTAL CAPITAL COSTS | 86.58 million 1990 $ |
| TOTAL O & M COSTS | 2.79 million 1990 $ |
| PLANT/WELL BASE COST: | 86.58 |
| OTHER COSTS: | 3.25 million 1990 $ |
| TOTAL PLANT/WELL BASE COST: | 89.83 million 1990 $ |
| WITH 30% CONTINGENCY: | 116.77 |
| NUMBER OF POWER PLANTS NEEDED: | 20.00 |
| TOTAL COST FOR POWER PLANTS: | 2335.46 million 1990 $ |
| SUBMARINE CABLE COSTS: | 374.56 million 1990 $ |
| OVERHEAD TRANSMISSION COSTS: | 298.94 million 1990 $ |
| TOTAL PROJECT CAPITAL COST: | 3008.96 million 1990 $ |
| WITH REPLACEMENT WELLS: | 3886.46 million 1990 $ |
| ANNUAL PROJECT O & M COST: | 55.71 million 1990 $ |

HAWAII GEOTHERMAL PROJECT COST ESTIMATE SHEET
25 NET MEGAWATT PLANT

HIGH ESTIMATE--1990 DOLLARS

| | |
|---|---|
| RESOURCE TEMPERATURE: | 350 DEG C |
| PLANT CAPACITY: | 27.5 MW (3 MW/WELL) |
| TECHNOLOGY (SF,DF,B): | SF |
| TERRAIN LABOR FACTOR (Y=1,N=0): | 0 |
| TERRAIN SITE PREP (Y=1,N=0): | 1 |
| CONSTRUCTION CAMP (Y=1,N=0): | 1 |
| PLANT O & M: LOW,PROB.,or HIGH | H |
| PRODUCTION EQUIPMENT: L,P,H | H |
| INJECTION EQUIPMENT: L,P,H | H |
| WELL O & M: L,P,H | H |
| ELECTRICITY COST: | 13 cents/kWh |
| TRANSMISSION LINE DISTANCE: | 10 miles |
| REMAINING ASSESSMENT WORK: | 3.00 million 1990 $ |
| PERMITS/LICENSES: | 1.00 million 1990 $ |
| # PRODUCTION WELLS: | 10 |
| # INJECTION WELLS: | 5 |
| # REPLACEMENT WELLS: | 15 |
| # UNSUCCESSFUL WELLS: | 10 |

WELLFIELD CAPITAL COSTS

| | |
|---|---|
| PRODUCTION EQUIPMENT | 6.13 |
| INJECTION EQUIPMENT | 5.72 |
| TERRAIN LABOR ADJUSTMENT | 0.00 |
| TERRAIN SITE PREP.ADJUSTMENT | 0.24 |
| CONSTRUCTION CAMP | 1.06 |
| S U B T O T A L (WELLFIELD) | 13.15 million 1984 $ |
| S U B T O T A L (WELLFIELD) | 14.32 million 1990 $ |
| WELLFIELD COST/MW | 0.52 million 1990 $ |
| WELLFIELD COST/KW | 521 1990 $ |
| WELL & WELLFIELD O & M COSTS | 1.10 million 1984 $ |
| WELL & WELLFIELD O & M COSTS | 1.19 million 1990 $ |

POWER PLANT CAPITAL COSTS

| | |
|---|---|
| POWER PLANT | 24.34 |
| H2S ABATEMENT | 9.70 |
| TERRAIN LABOR ADJUSTMENT | 0.00 |
| TERRAIN SITE PREP. ADJUSTMENT | 0.68 |
| CONSTRUCTION CAMP | 2.85 |
| S U B T O T A L (POWER PLANT) | 37.57 million 1984 $ |
| S U B T O T A L (POWER PLANT) | 40.91 million 1990 $ |
| POWER PLANT COST/MW | 1.49 million 1990 $ |
| POWER PLANT COST/KW | 1488 1990 $ |
| PLANT O & M COSTS | 3.32 million 1984 $ |
| PLANT O & M COSTS | 3.62 million 1990 $ |
| PLANT/WELLFIELD CAPITAL COSTS | 55.23 million 1990 $ |
| PLANT/WELLFIELD COST/MW | 2.01 million 1990 $ |
| PLANT/WELLFIELD COST/KW | 2008 1990 $ |
| WELL DRILLING COSTS | 45.00 million 1990 $ |
| TRANSMISSION LINE COSTS | 3.60 million 1990 $ |
| TOTAL CAPITAL COSTS | 103.83 million 1990 $ |
| TOTAL O & M COSTS | 4.81 million 1990 $ |
| POWER PLANT BASE COST: | 103.83 |
| OTHER COSTS: | 4.00 million 1990 $ |
| TOTAL POWER PLANT BASE COST: | 107.83 million 1990 $ |
| WITH 30% CONTINGENCY: | 140.18 |
| NUMBER OF POWER PLANTS NEEDED: | 20.00 |
| TOTAL COST FOR POWER PLANTS: | 2803.55 million 1990 $ |
| SUBMARINE CABLE COSTS: | 374.56 million 1990 $ |
| OVERHEAD TRANSMISSION COSTS: | 298.94 million 1990 $ |
| TOTAL PROJECT CAPITAL COST: | 3477.15 million 1990 $ |
| WITH REPLACEMENT WELLS: | 4647.15 million 1990 $ |
| ANNUAL PROJECT O & M COST: | 96.29 million 1990 $ |

HAWAII GEOTHERMAL PROJECT COST ESTIMATE SHEET
50 NET MEGAWATT PLANT

LOW ESTIMATE--1990 DOLLARS

| | |
|---|---|
| RESOURCE TEMPERATURE: | 350 DEG C |
| PLANT CAPACITY: | 55 MW (4 MW/WELL) |
| TECHNOLOGY (SF,DF,B): | SF |
| TERRAIN LABOR FACTOR (Y=1,N=0): | 0 |
| TERRAIN SITE PREP (Y=1,N=0): | 1 |
| CONSTRUCTION CAMP (Y=1,N=0): | 1 |
| PLANT O & M: LOW,PROB.,or HIGH | P |
| PRODUCTION EQUIPMENT: L,P,H | P |
| INJECTION EQUIPMENT: L,P,H | P |
| WELL O & M: L,P,H | P |
| ELECTRICITY COST: | 13 cents/kWh |
| TRANSMISSION LINE DISTANCE: | 10 miles |
| REMAINING ASSESSMENT WORK: | 2.50 million 1990 $ |
| PERMITS/LICENSES: | 0.75 million 1990 $ |
| # PRODUCTION WELLS: | 16 |
| # INJECTION WELLS: | 8 |
| # REPLACEMENT WELLS: | 24 |
| # UNSUCCESSFUL WELLS: | 16 |

WELLFIELD CAPITAL COSTS

| | |
|---|---|
| PRODUCTION EQUIPMENT | 9.79 |
| INJECTION EQUIPMENT | 7.77 |
| TERRAIN LABOR ADJUSTMENT | 0.00 |
| TERRAIN SITE PREP.ADJUSTMENT | 0.35 |
| CONSTRUCTION CAMP | 1.65 |
| S U B T O T A L (WELLFIELD) | 19.56 million 1984 $ |
| S U B T O T A L (WELLFIELD) | 21.30 million 1990 $ |
| WELLFIELD COST/MW | 0.39 million 1990 $ |
| WELLFIELD COST/KW | 387 1990 $ |
| WELL & WELLFIELD O & M COSTS | 1.52 million 1984 $ |
| WELL & WELLFIELD O & M COSTS | 1.66 million 1990 $ |

POWER PLANT CAPITAL COSTS

| | |
|---|---|
| POWER PLANT | 39.51 |
| H2S ABATEMENT | 10.34 |
| TERRAIN LABOR ADJUSTMENT | 0.00 |
| TERRAIN SITE PREP. ADJUSTMENT | 1.00 |
| CONSTRUCTION CAMP | 4.48 |
| S U B T O T A L (POWER PLANT) | 55.32 million 1984 $ |
| S U B T O T A L (POWER PLANT) | 60.24 million 1990 $ |
| POWER PLANT COST/MW | 1.10 million 1990 $ |
| POWER PLANT COST/KW | 1095 1990 $ |
| PLANT O & M COSTS | 2.94 million 1984 $ |
| PLANT O & M COSTS | 3.20 million 1990 $ |
| | |
| PLANT/WELLFIELD CAPITAL COSTS | 81.54 million 1990 $ |
| PLANT/WELLFIELD COST/MW | 1.48 million 1990 $ |
| PLANT/WELLFIELD COST/KW | 1483 1990 $ |
| WELL DRILLING COSTS | 67.50 million 1990 $ |
| TRANSMISSION LINE COSTS | 3.60 million 1990 $ |
| TOTAL CAPITAL COSTS | 152.64 million 1990 $ |
| | |
| TOTAL O & M COSTS | 4.85 million 1990 $ |
| | |
| PLANT/WELL BASE COST: | 152.64 |
| OTHER COSTS: | 3.25 million 1990 $ |
| TOTAL PLANT/WELL BASE COST: | 155.89 million 1990 $ |
| WITH 20% CONTINGENCY: | 187.07 |
| NUMBER OF POWER PLANTS NEEDED: | 10.00 |
| TOTAL COST FOR POWER PLANTS: | [illegible]70.73 million 1990 $ |
| SUBMARINE CABLE COSTS: | 374.56 million 1990 $ |
| OVERHEAD TRANSMISSION COSTS: | 298.94 million 1990 $ |
| | |
| TOTAL PROJECT CAPITAL COST: | 2544.23 million 1990 $ |
| WITH REPLACEMENT WELLS: | 3354.23 million 1990 $ |
| | |
| ANNUAL PROJECT O & M COST: | 48.54 million 1990 $ |

HAWAII GEOTHERMAL PROJECT COST ESTIMATE SHEET
50 NET MEGAWATT PLANT

HIGH ESTIMATE--1990 DOLLARS

| | |
|---|---|
| RESOURCE TEMPERATURE: | 350 DEG C |
| PLANT CAPACITY: | 55 MW (3 MW/WELL) |
| TECHNOLOGY (SF,DF,B): | SF |
| TERRAIN LABOR FACTOR (Y=1,N=0): | 0 |
| TERRAIN SITE PREP (Y=1,N=0): | 1 |
| CONSTRUCTION CAMP (Y=1,N=0): | 1 |
| PLANT O & M: LOW,PROB.,or HIGH | H |
| PRODUCTION EQUIPMENT: L,P,H | H |
| INJECTION EQUIPMENT: L,P,H | H |
| WELL O & M: L,P,H | H |
| ELECTRICITY COST: | 13 cents/kWh |
| TRANSMISSION LINE DISTANCE: | 10 miles |
| REMAINING ASSESSMENT WORK: | 3.00 million 1990 $ |
| PERMITS/LICENSES: | 1.00 million 1990 $ |
| # PRODUCTION WELLS: | 20 |
| # INJECTION WELLS: | 10 |
| # REPLACEMENT WELLS: | 30 |
| # UNSUCCESSFUL WELLS: | 20 |

WELLFIELD CAPITAL COSTS

| | |
|---|---|
| PRODUCTION EQUIPMENT | 12.16 |
| INJECTION EQUIPMENT | 9.39 |
| TERRAIN LABOR ADJUSTMENT | 0.00 |
| TERRAIN SITE PREP.ADJUSTMENT | 0.43 |
| CONSTRUCTION CAMP | 1.65 |
| S U B T O T A L (WELLFIELD) | 23.63 million 1984 $ |
| S U B T O T A L (WELLFIELD) | 25.74 million 1990 $ |
| WELLFIELD COST/MW | 0.47 million 1990 $ |
| WELLFIELD COST/KW | 468 1990 $ |
| WELL & WELLFIELD O & M COSTS | 2.33 million 1984 $ |
| WELL & WELLFIELD O & M COSTS | 2.54 million 1990 $ |

POWER PLANT CAPITAL COSTS

| | |
|---|---|
| POWER PLANT | 39.51 |
| H2S ABATEMENT | 15.51 |
| TERRAIN LABOR ADJUSTMENT | 0.00 |
| TERRAIN SITE PREP. ADJUSTMENT | 1.10 |
| CONSTRUCTION CAMP | 4.48 |
| S U B T O T A L (POWER PLANT) | 60.60 million 1984 $ |
| S U B T O T A L (POWER PLANT) | 65.99 million 1990 $ |
| POWER PLANT COST/MW | 1.20 million 1990 $ |
| POWER PLANT COST/KW | [illegible]20 1990 $ |
| PLANT O & M COSTS | 5.36 million 1984 $ |
| PLANT O & M COSTS | 5.84 million 1990 $ |
| | |
| PLANT/WELLFIELD CAPITAL COSTS | 91.72 million 1990 $ |
| PLANT/WELLFIELD COST/MW | 1.67 million 1990 $ |
| PLANT/WELLFIELD COST/KW | 1668 1990 $ |
| WELL DRILLING COSTS | 90.00 million 1990 $ |
| TRANSMISSION LINE COSTS | 3.60 million 1990 $ |
| TOTAL CAPITAL COSTS | 185.32 million 1990 $ |
| | |
| TOTAL O & M COSTS | 8.38 million 1990 $ |
| | |
| POWER PLANT BASE COST: | 185.32 |
| OTHER COSTS: | 4.00 million 1990 $ |
| TOTAL POWER PLANT BASE COST: | 189.32 million 1990 $ |
| WITH 20% CONTINGENCY: | 227.19 |
| NUMBER OF POWER PLANTS NEEDED: | 10.00 |
| TOTAL COST FOR POWER PLANTS: | [illegible]71.33 million 1990 $ |
| SUBMARINE CABLE COSTS: | 374.56 million 1990 $ |
| OVERHEAD TRANSMISSION COSTS: | 298.94 million 1990 $ |
| | |
| TOTAL PROJECT CAPITAL COST: | 2945.38 million 1990 $ |
| WITH REPLACEMENT WELLS: | 4025.38 million 1990 $ |
| | |
| ANNUAL PROJECT O & M COST: | 83.82 million 1990 $ |

## HAWAII GEOTHERMAL PROJECT COST ESTIMATE SHEET
## 50 NET MEGAWATT PLANT

### LOW ESTIMATE--1990 DOLLARS

| | |
|---|---|
| RESOURCE TEMPERATURE: | 350 DEG C |
| PLANT CAPACITY: | 55 MW (4 MW/WELL) |
| TECHNOLOGY (SF,DF,B): | SF |
| TERRAIN LABOR FACTOR (Y=1,N=0): | 0 |
| TERRAIN SITE PREP (Y=1,N=0): | 1 |
| CONSTRUCTION CAMP (Y=1,N=0): | 1 |
| PLANT O & M: LOW,PROB.,or HIGH | P |
| PRODUCTION EQUIPMENT: L,P,H | P |
| INJECTION EQUIPMENT: L,P,H | P |
| WELL O & M: L,P,H | P |
| ELECTRICITY COST: | 13 cents/kWh |
| TRANSMISSION LINE DISTANCE: | 10 miles |
| REMAINING ASSESSMENT WORK: | 2.50 million 1990 $ |
| PERMITS/LICENSES: | 0.75 million 1990 $ |
| # PRODUCTION WELLS: | 16 |
| # INJECTION WELLS: | 8 |
| # REPLACEMENT WELLS: | 24 |
| # UNSUCCESSFUL WELLS: | 16 |
| **WELLFIELD CAPITAL COSTS** | |
| PRODUCTION EQUIPMENT | 9.79 |
| INJECTION EQUIPMENT | 7.77 |
| TERRAIN LABOR ADJUSTMENT | 0.00 |
| TERRAIN SITE PREP.ADJUSTMENT | 0.35 |
| CONSTRUCTION CAMP | 1.65 |
| S U B T O T A L (WELLFIELD) | 19.56 million 1984 $ |
| S U B T O T A L (WELLFIELD) | 21.30 million 1990 $ |
| WELLFIELD COST/MW | 0.39 million 1990 $ |
| WELLFIELD COST/KW | 387 1990 $ |
| WELL & WELLFIELD O & M COSTS | 1.52 million 1984 $ |
| WELL & WELLFIELD O & M COSTS | 1.66 million 1990 $ |
| **POWER PLANT CAPITAL COSTS** | |
| POWER PLANT | 39.51 |
| H2S ABATEMENT | 10.34 |
| TERRAIN LABOR ADJUSTMENT | 0.00 |
| TERRAIN SITE PREP. ADJUSTMENT | 1.00 |
| CONSTRUCTION CAMP | 4.48 |
| S U B T O T A L (POWER PLANT) | 55.32 million 1984 $ |
| S U B T O T A L (POWER PLANT) | 60.24 million 1990 $ |
| POWER PLANT COST/MW | 1.10 million 1990 $ |
| POWER PLANT COST/KW | 1095 1990 $ |
| PLANT O & M COSTS | 2.94 million 1984 $ |
| PLANT O & M COSTS | 3.20 million 1990 $ |
| PLANT/WELLFIELD CAPITAL COSTS | 81.54 million 1990 $ |
| PLANT/WELLFIELD COST/MW | 1.48 million 1990 $ |
| PLANT/WELLFIELD COST/KW | 1483 1990 $ |
| WELL DRILLING COSTS | 67.50 million 1990 $ |
| TRANSMISSION LINE COSTS | 3.60 million 1990 $ |
| TOTAL CAPITAL COSTS | 152.64 million 1990 $ |
| TOTAL O & M COSTS | 4.85 million 1990 $ |
| PLANT/WELL BASE COST: | 152.64 |
| OTHER COSTS: | 3.25 million 1990 $ |
| TOTAL PLANT/WELL BASE COST: | 155.09 million 1990 $ |
| WITH 30% CONTINGENCY: | 202.66 |
| NUMBER OF POWER PLANTS NEEDED: | 10.00 |
| TOTAL COST FOR POWER PLANTS: | 2026.62 million 1990 $ |
| SUBMARINE CABLE COSTS: | 374.56 million 1990 $ |
| OVERHEAD TRANSMISSION COSTS: | 298.94 million 1990 $ |
| TOTAL PROJECT CAPITAL COST: | 2700.12 million 1990 $ |
| WITH REPLACEMENT WELLS: | 3577.62 million 1990 $ |
| ANNUAL PROJECT O & M COST: | 48.54 million 1990 $ |

## HAWAII GEOTHERMAL PROJECT COST ESTIMATE SHEET
## 50 NET MEGAWATT PLANT

### HIGH ESTIMATE--1990 DOLLARS

| | |
|---|---|
| RESOURCE TEMPERATURE: | 350 DEG C |
| PLANT CAPACITY: | 55 MW (3 MW/WELL) |
| TECHNOLOGY (SF,DF,B): | SF |
| TERRAIN LABOR FACTOR (Y=1,N=0): | 0 |
| TERRAIN SITE PREP (Y=1,N=0): | 1 |
| CONSTRUCTION CAMP (Y=1,N=0): | 1 |
| PLANT O & M: LOW,PROB.,or HIGH | H |
| PRODUCTION EQUIPMENT: L,P,H | H |
| INJECTION EQUIPMENT: L,P,H | H |
| WELL O & M: L,P,H | H |
| ELECTRICITY COST: | 13 cents/kWh |
| TRANSMISSION LINE DISTANCE: | 10 miles |
| REMAINING ASSESSMENT WORK: | 3.00 million 1990 $ |
| PERMITS/LICENSES: | 1.00 million 1990 $ |
| # PRODUCTION WELLS: | 20 |
| # INJECTION WELLS: | 10 |
| # REPLACEMENT WELLS: | 30 |
| # UNSUCCESSFUL WELLS: | 20 |
| **WELLFIELD CAPITAL COSTS** | |
| PRODUCTION EQUIPMENT | 12.16 |
| INJECTION EQUIPMENT | 9.39 |
| TERRAIN LABOR ADJUSTMENT | 0.00 |
| TERRAIN SITE PREP.ADJUSTMENT | 0.43 |
| CONSTRUCTION CAMP | 1.65 |
| S U B T O T A L (WELLFIELD) | 23.63 million 1984 $ |
| S U B T O T A L (WELLFIELD) | 25.74 million 1990 $ |
| WELLFIELD COST/MW | 0.47 million 1990 $ |
| WELLFIELD COST/KW | 468 1990 $ |
| WELL & WELLFIELD O & M COSTS | 2.33 million 1984 $ |
| WELL & WELLFIELD O & M COSTS | 2.54 million 1990 $ |
| **POWER PLANT CAPITAL COSTS** | |
| POWER PLANT | 39.51 |
| H2S ABATEMENT | 15.51 |
| TERRAIN LABOR ADJUSTMENT | 0.00 |
| TERRAIN SITE PREP. ADJUSTMENT | 1.10 |
| CONSTRUCTION CAMP | 4.48 |
| S U B T O T A L (POWER PLANT) | 60.60 million 1984 $ |
| S U B T O T A L (POWER PLANT) | 55.39 million 1990 $ |
| POWER PLANT COST/MW | 1.20 million 1990 $ |
| POWER PLANT COST/KW | 1200 1990 $ |
| PLANT O & M COSTS | 5.36 million 1984 $ |
| PLANT O & M COSTS | 5.84 million 1990 $ |
| PLANT/WELLFIELD CAPITAL COSTS | 91.72 million 1990 $ |
| PLANT/WELLFIELD COST/MW | 1.67 million 1990 $ |
| PLANT/WELLFIELD COST/KW | 1668 1990 $ |
| WELL DRILLING COSTS | 90.00 million 1990 $ |
| TRANSMISSION LINE COSTS | 3.60 million 1990 $ |
| TOTAL CAPITAL COSTS | 185.32 million 1990 $ |
| TOTAL O & M COSTS | 8.38 million 1990 $ |
| POWER PLANT BASE COST: | 185.32 |
| OTHER COSTS: | 4.00 million 1990 $ |
| TOTAL POWER PLANT BASE COST: | 189.32 million 1990 $ |
| WITH 30% CONTINGENCY: | 246.12 |
| NUMBER OF POWER PLANTS NEEDED: | 10.00 |
| TOTAL COST FOR POWER PLANTS: | 2461.20 million 1990 $ |
| SUBMARINE CABLE COSTS: | 374.56 million 1990 $ |
| OVERHEAD TRANSMISSION COSTS: | 298.94 million 1990 $ |
| TOTAL PROJECT CAPITAL COST: | 3134.70 million 1990 $ |
| WITH REPLACEMENT WELLS: | 4304.70 million 1990 $ |
| ANNUAL PROJECT O & M COST: | 83.82 million 1990 $ |

# APPENDIX C

## CRITICISM, REVIEW AND COMMENTS ON THE FEBRUARY, 1988 DECISION ANALYSTS HAWAII, INC. REPORT

Alex Sifford is currently Geothermal Program Manager for the Resource Development Division of the Oregon Department of Energy. The following are comments from his review of the February 1988 Decision Analysts Hawaii, Inc. report on the Economic Feasibility of the Hawaii Geothermal and Cable project.

Comments concerning the February 1988 Hawaii Department of Business and Economic Development Economic Feasibility Analysis regarding the proposed Hawaii Geothermal Project.

| | |
|---|---|
| Pg P-1 (last paragraph) | (On resource quality) A high temperature resource is not necessarily a high quality resource. Hawaii has a high temperature resource but its quality is as yet unproven. Problems with seawater intrusion, silica and mineral content, unknown long-term production capability, and inherent development dangers reduce the quality potential considerably. |
| Pg ES-2 (first paragraph) | (On overall system planning) To say the inclusion of Maui in the system would have no effect on its economic feasibility is unsubstantiated. Experience in the Pacific Northwest has shown interties can be difficult and expensive if not considered early in the system planning process. |
| Pg ES-2 (third paragraph) | (On who benefits) Apparently all the geothermal power will to go Oahu. Does the Big Island get nothing? |
| Pg ES-3 (mid-page table) | (On plant sizing) To produce 500 net MW of power, plants must be sized to allow for approximately 10% loss in generation and transmission. |
| Pg ES-7 (second paragraph) | (On development schedules) Realistically, geothermal companies would develop the resource in stages since it can be so variable and costly. Full and rapid development, in light of The Geysers experience, is not a logical approach. |
| Pg I-2 (last paragraph) | (On plant construction time) The report indicates it is conservative in terms of size of plants and pace of development but states its plants will be built in half the time or less than construction time estimates by Stone & Webster Engineers of Denver, Colorado who are well experienced at design and construction. |
| Pg IV-3 (first paragraph) | (On steam gathering system costs) Bechtel figures for a steamgathering system is closer to $7 million. |

| | |
|---|---|
| Pg IV-3 (powerplant section) | (On power plant costs)<br>Based on Oregon Department of Energy studies, actual cost per kilowatt is for 25 MW is between $1,600 and $1,800. The $1,100/kW in the report ($27.734 million divided by 25 MW) is very low. |
| Pg IV-4 (second paragraph) | (On well development)<br>Ten months for well development is extremely optimistic. At 13 wells per plant it allows less than one month per well. Six weeks seems more likely. |
| Pg IV-4 (last paragraph) | (On well O&M costs)<br>The $58,000 per well O&M cost is unsubstantiated and seems very low. Our own (Oregon Dept. of Energy) estimates show a $200,000 to $800,000 per well range for O&M. |
| Pg IV-5 (second paragraph) | (On waste disposal costs)<br>The chemical and waste disposal costs are unsubstantiated. How are these costs estimated on an undefined resource? |
| Pg IV-5 (third paragraph) | (On costs in general)<br>Where is the contingency cost for undefined resource. A contingency is only logical given what little is known about the resource. |
| Pg IV-6 (third paragraph) | (On locating the plants)<br>Where are the maps showing volcanic activity and proposed plant locations? |
| Pg IV-8 (sixth paragraph) | (On insurance costs)<br>Insurance would be extraordinarily high due to risks. The figure 0.3% seems low. |
| Pg IV-9 (fourth paragraph) | (On financing)<br>Twenty-four years is too long for financing. Seven years is more likely. |
| Pg IV-12 (first paragraph) | (On risk to investors)<br>Major sources of risk and uncertainty are not greatly reduced since the development scenario is not logically staged. |

Carl Freedman is a utility economist living in Hawaii. He currently serves as Vice President of Legal Affairs and Board Member of the Blue Ocean Society. He is formerly a member of the Oregon Environmental Action Group 'Forelaws On Board' and played an integral part in that groups examination and analysis of the proposed Pebble Springs Nuclear Facility. He has been a major participant and contributor in many comprehensive studies on conservation and alternate energy systems. The following is his assessment and critique of the February 1988 Decision Analysts Hawaii, Inc. report on the economic feasibility of the proposed Hawaii Geothermal and Cable Project.

AN ASSESSMENT AND CRITIQUE OF:

# DEPARTMENT OF BUSINESS AND ECONOMIC DEVELOPMENT ECONOMIC FEASIBILITY ANALYSIS REGARDING THE HAWAII GEOTHERMAL/UNDERWATER CABLE PROJECT

PREPARED BY CARL FREEDMAN
12/4/89

## BACKGROUND

The State of Hawaii and the Hawaii Electric Company (HECO) are undertaking an aggressively accelerated program to develop 500 megawatts of geothermal electrical generating capacity on the island of Hawaii in conjunction with a deep underwater and overland transmission system to transport the generated energy to the island of Oahu. The Hawaii Department of Business and Economic Development (DBED) has taken a lead role in the promotion of this enterprise.

DBED has commissioned studies which provide the basis for its conclusions that the geothermal/cable Project is economically feasible. A preliminary study was published in April of 1986: "Alternative Approaches to the Legal, Institutional and Financial Aspects of Developing an Inter-Island Electrical Transmission System,." prepared by Gerald A. Sumida et al. Subsequently, a study was commissioned to address economic concerns more specifically: "Undersea Cable to Transmit Geothermal-Generated Electrical Energy from the Island of Hawaii to Oahu: Economic Feasibility," prepared by Decision Analysts Hawaii, Inc., published in February, 1988. This latter study (DAHI study) is the basis for the projected capital costs of the geothermal/cable Project of $ 1.7 billion.

The Hawaiian Electric Company (HECO) issued Requests for Proposals to private industrial consortia to solicit proposed schemes to build, finance and manage the geothermal/cable Project. Four or five consortia have responded with proposals which are being reviewed by HECO and a consulting firm. A condition in the request for proposals was that the projected delivered cost of energy to Oahu would be at or below HECO's avoided cost of energy.

According to DBED literature the project would be financed, built and owned by a private corporate entity (or entities.) The project owner would (according to DBED's interpretation) bear all of the financial risks of project cost overruns or generation and transmission problems. Revenues for the project would be provided by a contract with HECO, binding Heco to purchase power delivered by the project to Oahu.

CONCERNS REGARDING PROJECT ECONOMICS AND FINANCING

According to the best published hopes of DBED and HECO the geothermal/cable project could be built, financed and operated without costs or risks to ratepayers or taxpayers above what it would cost to generate electrical energy with oil-fired facilities. Ignoring all of the environmental, social, archeological, health and aesthetic issues not addressed by current economic analyses, this would be a welcome reassurance to residents of the state regarding the vulnerability of their pocketbooks.

Careful analysis of the DAHI study, however, indicates that the projected costs of building and financing the geothermal/cable project have been substantially underestimated and improperly compared to HECO's avoided costs (see discussion below.) This raises concerns over the cost impacts to Hawaiian residents which are potentially enormous. The details regarding how the proposals solicited by HECO will be assessed and the particular language and terms included in any subsequent proposed contracts are of crucial importance.

(1) Will the proposals solicited by HECO indicate project costs greater than HECO's avoided costs? If so, will the project still be considered by HECO?

(2) Will the proposals solicited by HECO propose to meet avoided costs by transferring financial risks to ratepayers, taxpayers, or utility stockholders ?

(3) Will the proposals solicited by HECO incorporate low-ball bids in anticipation of later re-negotiation or litigation?

Ostensibly, according to intended planned contractual arrangements, the ratepayers are to be insulated from costs exceeding HECO's avoided costs. Much previous experience with over-budget and non-functional electrical generation projects on the mainland has demonstrated that this promise may be a costly illusion. Corporations that have invested billions of dollars in a generating project in response to requests by the State of Hawaii and HECO are not going to absorb large cost overruns without litigating the matter tooth and nail in the courts. Contracts arranged on the basis proposed by DBED are not likely to be enforceable.

It is of paramount importance for these reasons to insure that any contractual agreements made by HECO, the State of Hawaii, or project consortia be examined very carefully to insure that they are based upon sound and reasonable economic assumptions, or they may end up being economic disasters paid for by Hawaii's ratepayers and/or taxpayers. From an economic point of view, the proposed projects will only be successful if they are in fact, actually economically prudent, regardless of any contractual schemes or promises.

## ASSESSMENT OF DECISION ANALYSTS HAWAII STUDY

### OVERVIEW

Currently, DBED's economic projections of the economics of the geothermal/cable project are based upon the study by Decision Analysts Hawaii, Inc. published in February of 1988.

The study assumes that the cable and transmission system will be built and financed by one private corporate "venture" and that the geothermal wells and generation facilities will be built by another similar venture, perhaps under the ownership of a common larger corporation. Estimates are made of the costs of building the various components of the geothermal/cable project based upon other studies and by scaling costs from other projects. The study establishes schedules of year by year expenditures, revenues, and bond sales and payments. The schedules are discounted to present values and are compared with estimates of present values of HECO's avoided fuel, operating and capital costs. By various indicators of venture profitability, break-even fuel oil cost and cost to benefit ratios, the costs of the geothermal are evaluated as being economically feasible.

Though the study is rigorous in its treatment of cash flows and discounting methodologies, it makes some simple errors that are of significant consequence to the outcome of its conclusions. The study assumes 100% availability factors for geothermal generation and transmission. No transmission losses are accounted for. Assumptions are made regarding financing methodologies that are inconsistent with conventional experience and would not in certain instances be legal without legislative actions. Real generation capital cost escalation is ignored. Capital costs are in certain instances substantially underestimated. Certain methods of scaling generation plant capital costs are misapplied.

## CRITIQUE

### GENERATION AND TRANSMISSION AVAILABILITY

The text of the DAHI study acknowledges that generation and transmission facilities will have some required maintenance and outage time. In the actual arithmetic of revenue calculations used in the study, however, no such adjustment is made. Revenues are calculated based upon 500 MW of power output for 8760 hours per year (100% availability.) The study states at one point in the text that each 25 MW geothermal generation plant will be built to 27.5 MW capacity to account for maintenance time, however, no such adjustment was actually made to the capital cost or operating expenses used in the calculations. The calculations used in the study assume 100% availability and 100% capacity factors for geothermal, transmission and AC-DC conversion facilities.

There is no such thing in the world of electrical power generation as a plant operating at 100% availability. Planned maintenance and unplanned outages are inevitable. Transmission system outage percentages are typically quite small, but would be additive to generation outage times. A 90% overall availability would be very optimistic for a geothermal/cable system. This statistic is important because it directly and proportionately effects the amount of energy delivered by the geothermal/cable system and the revenues accrued by the geothermal/cable ventures.

### TRANSMISSION LOSSES

The DAHI study compares the costs of geothermal generation on the island of Hawaii to meet Oahu's needs with local generation on Oahu. Although the study mentions in its text that revenue calculations are based upon delivered energy to Oahu (rather than generated energy) there is no accounting of transmission losses anywhere in the actual calculations of revenue or generation costs. Revenue is calculated based upon delivering 500 MW of power to Oahu 100% of the time, generated by 500 MW of capacity on Hawaii. Transmission losses directly and proportionately effect the amount of delivered energy and accrued revenues of the geothermal/cable venture. Transmission losses are typically at least 10% for a system like the one proposed in this project.

### ECONOMY OF SCALE CALCULATIONS

The DAHI study estimates the costs of a series of twenty power plants of 25 MW capacity. The costs for these plants are "scaled" from the documented costs of 12.5 MW plants. The concept used in scaling is that a larger plant is cheaper per MW because of the economy of scale. A boiler twice as big costs less than twice as much. The formula used in the DAHI study is the ".6 power" rule which is commonly used in scaling generation facility capital costs. According to this formula a 25 MW plant costs 51.6% more than a 12.5 MW plant. This is an appropriate application of scaling capital costs.

The DAHI study goes further than this, however. It groups the power plants into clusters of fours and reduces the costs of the second and forth plants in each group to 70% of the scaled cost and reduces the third plant to 80% of the scaled cost. The logic used is that the plants will be close enough together that they can share certain of their facilities and thus net cost savings. The net capital costs for the network of generating facilities is reduced by this treatment of costs to an average of 80% of the previously scaled costs. This treatment is not conventional. It is especially not appropriate in this instance because of other assumptions made in the analysis. In the section of the study that addresses risks due to geological hazards it is stressed that the plants are distributed widely to avoid damage to more than one plant at a time due to lave flows. This is a very sensitive assumption because it is the basis for conclusions made by the study that there would be no loss in system net output and no loss in revenues due to geologic hazards (a possible loss of one plant.) Grouping the plants close enough to benefit from economies of scale is not consistent with this assumption.

Additionally, the DAHI study uses the same .6 power rule to scale the capital costs of wellfield steam-gathering equipment as it uses to scale generation plant equipment. This is inappropriate. Steam-gathering equipment does not become less expensive per MW for a larger field than for a smaller one according to a .6 power rule. If anything, much of the costs per MW increase as wellfield size increases because of the longer average distances between each well and the power plant. A smaller power plant is located in a smaller wellfield and is consequently relatively close to the wells that supply it. As the size of a power plant increases, the size of the wellfield dedicated to the plant increases and the average distance of each well to the power plant increases. Steam-gathering piping costs increase as the average distance to the power plant increases. This principle dictates that the cost per MW for steam gathering piping <u>increases</u> as the size of the power plant increases. The DAHI study erroneously makes the opposite assumption and calculates the cost of a 25 MW steam-gathering system by <u>decreasing</u> the costs per MW of steam gathering equipment according to the .6 power rule from the documented costs for 12.5 MW plant equipment. Furthermore, the assumption noted above that plants will be grouped in clusters of four closely enough to benefit from economies of scale would further aggravate the need for even longer and consequently more expensive steam-gathering equipment.

## WELLFIELD COSTS

Perhaps the most sensitive single set of assumptions regarding the costs of the geothermal/cable venture are the estimates of the costs of drilling a productive wellfield. Approximately one third of the total project costs are in the wellfield. The primary factor effecting wellfield costs is the number of wells necessary to develop the required thermal energy for generation purposes. Some of the wells drilled would be productive. Some would be used for fluid re-injection. Some would be dry, or too hot or cool. Some would need to be replaced over the life of the facility. The DAHI study assumes that 13 wells, plus eight replacement wells, will be required for each 25 MW plant. This equates to useable/non-useable ratio of 5:1. This ratio may be very optimistic for Hawaii geology.

Although DBED and the DAHI study repeatedly state that geothermal resources are a proven and reliable resource, there is really very little experience in areas geologically similar to Hawaii (a live volcano.) Hawaii is a hot, and therefore a potentially efficient resource, but it is also a very young, active and potentially unstable geological region. The area of the world with the most similar geology that has operating experience with geothermal wells is Iceland. There the experience with geothermal electrical generation has not been good. The geology seems to be too active, effecting the success rates of the wells dramatically. The project there required 24 wells to be drilled to obtain 11 that were useable. It remains to be seen how many replacement wells will be necessary. Iceland experienced problems with wells "pinching off" rendering them unusable and did not attain the sustained power levels that were anticipated. The second unit of the planned two-unit geothermal generation facility there has been abandoned because of the wellfield problems and expenses.

Without much experience with Hawaiian geology, predicting the productivity and success rate of wells is quite conjectural. The wellfield success rate assumed in the DAHI study is perhaps possible, but must certainly be categorized as quite optimistic. These assumptions effect the certainty of any economic predictions dramatically.

## CAPITAL COST ESTIMATES

The DAHI study is consistently optimistic about estimates of capital costs. The cost estimate for AC-DC conversion stations, for example, is $ 72 million. According to current estimates from B.C. Hydro, the costs would be $250 per KW for each station, totalling $ 250 million. The DAHI cost estimate for the <u>entire</u> transmission system including the underwater cables, overhead lines, pumping stations and AC-DC conversion station is $ 413.3 million.

The geothermal/cable project incorporates several aspects of new unproven technologies in new untried areas of geological and geographical extremes. Even in conventional projects of this magnitude it is prudent for planning purposes to include contingency costs to include what is more a probability than a possibility of project delays, technical problems and cost overruns. No such contingencies are considered by the study.

## REAL COST ESCALATION

In order to calculate HECO's future avoided costs DAHI escalates the real cost of fuel oil according to the average of a series of estimates of future oil prices. The real escalation of fuel prices is substantial. (Real cost escalation is the increase over and above that due to inflation.) These avoided fuel costs are compared directly with various costs of geothermal generation. The study does not make the appropriate analogous accounting of the real cost escalation of plant capital costs. (Geothermal generation costs are primarily capital costs.) Historical experience indicates that real plant capital costs escalate faster than real fuel prices during periods of real fuel price increases. Utility planners know, for example, that their older plants were less expensive to build than their newer plants, even in terms of real costs. (This may not be true in operating or fuel costs, however.) Because the DAHI study is comparative in nature, the differences in the treatment of cost escalation skew the results in favor of the geothermal/cable venture.

## FINANCING

The DAHI study assumes that the cable and transmission system will be financed with Hawaii Special Purpose Revenue Bonds (Industrial Development Bonds) at a rate .5% above municipal bond rates. The geothermal venture is assumed to float bonds at the Aaa corporate rate. At the same time the study maintains that all financial risks due to cost over-runs or resource failure are to be borne by these financing sources. These are clearly not realistic assumptions.

Hawaii Special Purpose Revenue Bonds are not available for non-regulated private corporate use.

The assumption that the geothermal/cable venture can be financed by bonds issued at such low interest rates with such a substantial assumption of risk is inappropriate, especially in a comparative study of this nature. The costs of financing appreciably effect the profitability equation used in the DAHI study.

## SENSITIVITY ANALYSIS

Throughout the DAHI study estimates and calculated numbers are associated with standard deviations to imply confidence intervals around the predicted statistics. This sort of analysis has its place in the laboratory, in demographics and perhaps around casino gambling tables. The use of confidence intervals in a study of this nature which is designed to be used by policy decision-makers is inappropriate and misleading. To a person familiar with statistics these numbers may be of some value, but to imply to a decision-maker who may rely on the study that the values ascribed to the confidence intervals are realistic indicators of the possibility of error of the study is ludicrous.

Even from a purely statistical viewpoint the sensitivity analysis is misapplied. This type of analysis is only appropriate when all of the input parameters are truly independent of one another and are normally distributed. Neither of these conditions are met in a construction project where delays in one portion of the project can effect scheduling and costs of other portions and where the potential for cost overruns exceed the margin of potential cost savings.

Furthermore, the sensitivity analysis only takes into account one particular type of error. It ignores the types of errors noted above, which are incremental, but when taken as a whole substantially effect the outcome of the analysis. The omission by the DAHI study of any consideration of transmission losses and availability factors effects the overall calculations in the cost comparison by at least 21%, and depending on actual achieved availability factors, perhaps by 46% or more.

Approximate percentage impacts to the DAHI study projected costs are listed below to give some idea of the magnitude of their importance. These numbers are not intended as correction factors to adjust the DAHI study results to draw more accurate conclusions. They are included here to demonstrate the sensitivity of the DAHI study to its own oversights and biases. All figures are percentages of the total geothermal/cable project costs/revenues.

The cumulative percentage statistics below are only for order-of-magnitude comparison purposes. The high-end statistics may include some double-counting as, for example, in the case of generation availability being improved by additional wellfield improvements.

| | |
|---|---|
| GENERATION AND TRANSMISSION AVAILABILITY | 10 - 30% |
| TRANSMISSION LOSSES | 10 - 12% |
| CLUSTERING CAPITAL COST REDUCTIONS | 6% |
| SCALING STEAM-GATHERING SYSTEM | 6% |
| WELLFIELD COSTS - (AS IN ICELAND) | 10 - 20% |
| CONVERTER STATION ACTUAL COSTS | 8% |
| CAPITAL COST ESCALATION | 4% |
| FINANCING BOND RATES | 5 - 10% |
| CUMULATIVE | 76 - 143% |

These statistics indicate that the DAHI study includes errors and oversights that substantially effect the outcome of its conclusions, well in excess of the confidence intervals implied in its sensitivity analysis.

## CONCLUSIONS

The proposed geothermal/cable project is a very large and expensive project with an enormous potential to impact the economy of the State of Hawaii. Currently existing economic analyses do not establish a sound basis for confidence in the ultimate cost-effectiveness of the project. Very careful scrutiny must be given to the details of proposed project bids and contractual arrangements to assure that financial risks and the costs of project failures or overruns will not be assumed by Hawaii's ratepayers or taxpayers or HECO's stockholders.

# APPENDIX D

## ROBERT J. MOWRIS REPORT

# APPENDIX E

## COSTS IF PRODUCTION WELL INCREASES TO 200% REPLACEMENT

AVERAGE KWH COST OF ELECTRICITY OVER 40 YEARS IF 500MW OF OTHER GENERATING CAPACITY IS ADDED TO EXISTING CAPACITY USING A 1990 ELECTRICITY USE AND COST ESTIMATE AS A BASE
(20% Contingency)
(3/1 Well Replacement)

| GEOTHERMAL LOW | | GEOTHERMAL HIGH |
|---|---|---|
| | **EXISTING SYSTEM (1990)** | |
| 10,757,280,000 | Total kWh Capacity | 10,757,280,000 |
| 8,264,379,327 | With 23% Reserve | 8,264,379,327 |
| 613,974,852 | $ Operating Revenue | 613,974,852 |
| 8,264,379,327 | Annual kWh Sold | 8,264,379,327 |
| 7.43 | Average Cents/kWh | 7.43 |
| | **ADDED CAPACITY (25MW PLANTS) (40 Years)** | |
| 13,270,000,000 | $ Project Cost | 16,560,000,000 |
| 101,791,000,000 | kWh Sold | 101,791,000,000 |
| 13.04 | Average Cents/kWh With Royalty | 16.27 |
| | **COMBINED CAPACITY (40 Years)** | |
| 37,828,994,071 | $ Operating Revenue | 41,118,994,071 |
| 408,777,045,306 | kWh Sold | 408,777,045,306 |
| 9.25 | Average Cents/kWh | 10.06 |
| 1.83 | Cents/kWh Increase With Added Capacity | 2.63 |
| 24.6% | Cents/kWh % Increase With Added Capacity | 35.4% |

| GEOTHERMAL LOW | | GEOTHERMAL HIGH |
|---|---|---|
| | **EXISTING SYSTEM (1990)** | |
| 10,757,280,000 | Total kWh Capacity | 10,757,280,000 |
| 8,264,379,327 | With 23% Reserve | 8,264,379,327 |
| 613,974,852 | $ Operating Revenue | 613,974,852 |
| 8,264,379,327 | Annual kWh Sold | 8,264,379,327 |
| 7.43 | Average Cents/kWh | 7.43 |
| | **ADDED CAPACITY (50MW PLANTS) (40 Years)** | |
| 12,030,000,000 | $ Project Cost | 15,010,000,000 |
| 98,813,000,000 | kWh Sold | 98,813,000,000 |
| 12.17 | Average Cents/kWh With Royalty | 15.19 |
| | **COMBINED CAPACITY (40 Years)** | |
| 36,588,994,071 | $ Operating Revenue | 39,568,994,071 |
| 406,409,169,409 | kWh Sold | 406,409,169,409 |
| 9.00 | Average Cents/kWh | 9.73 |
| 1.57 | Cents/kWh Increase With Added Capacity | 2.31 |
| 21.2% | Cents/kWh % Increase With Added Capacity | 31.0% |

| SOLAR/OIL | | OIL |
|---|---|---|
| | **EXISTING SYSTEM (1990)** | |
| 10,757,280,000 | Total kWh Capacity | 10,757,280,000 |
| 8,264,379,327 | With 23% Reserve | 8,264,379,327 |
| 613,974,852 | $ Operating Revenue | 613,974,852 |
| 8,264,379,327 | Annual kWh Sold | 8,264,379,327 |
| 7.43 | Average Cents/kWh | 7.43 |
| | **ADDED CAPACITY (100MW PLANTS) (40 Years)** | |
| 10,610,000,000 | $ Project Cost | 8,570,000,000 |
| 98,112,000,000 | kWh Sold | 98,112,000,000 |
| 10.81 | Average Cents/kWh With Royalty | 8.73 |
| | **COMBINED CAPACITY (40 Years)** | |
| 35,168,994,071 | $ Operating Revenue | 33,128,994,071 |
| 405,950,619,709 | kWh Sold | 405,950,619,709 |
| 8.66 | Average Cents/kWh | 8.16 |
| 1.23 | Cents/kWh Increase With Added Capacity | 0.73 |
| 16.6% | Cents/kWh % Increase With Added Capacity | 9.8% |

**AVERAGE KWH COST OF ELECTRICITY OVER 40 YEARS IF 500MW OF OTHER GENERATING CAPACITY IS ADDED TO EXISTING CAPACITY USING A 1990 ELECTRICITY USE AND COST ESTIMATE AS A BASE**

**(30% Contingency)**

**(3/1 Well Replacement)**

| | | |
|---|---|---|
| | EXISTING SYSTEM (1990) | |
| 10,757,280,000 | Total kWh Capacity | 10,757,280,000 |
| 8,264,379,327 | With 23% Reserve | 8,264,379,327 |
| 613,974,852 | $ Operating Revenue | 613,974,852 |
| 8,264,379,327 | Annual kWh Sold | 8,264,379,327 |
| 7.43 | Average Cents/kWh | 7.43 |
| GEOTHERMAL LOW | ADDED CAPACITY (25MW PLANTS) (40 Years) | GEOTHERMAL HIGH |
| 13,970,000,000 | $ Project Cost | 17,430,000,000 |
| 101,791,000,000 | kWh Sold | 101,791,000,000 |
| 13.72 | Average Cents/kWh With Royalty | 17.12 |
| | COMBINED CAPACITY (40 Years) | |
| 38,528,994,071 | $ Operating Revenue | 41,988,994,071 |
| 408,777,085,306 | kWh Sold | 408,777,085,306 |
| 9.43 | Average Cents/kWh | 10.27 |
| 2.00 | Cents/kWh Increase With Added Capacity | 2.84 |
| 26.9% | Cents/kWh % Increase With Added Capacity | 38.3% |

| | | |
|---|---|---|
| | EXISTING SYSTEM (1990) | |
| 10,757,280,000 | Total kWh Capacity | 10,757,280,000 |
| 8,264,379,327 | With 23% Reserve | 8,264,379,327 |
| 613,974,852 | $ Operating Revenue | 613,974,852 |
| 8,264,379,327 | Annual kWh Sold | 8,264,379,327 |
| 7.43 | Average Cents/kWh | 7.43 |
| GEOTHERMAL LOW | ADDED CAPACITY (50MW PLANTS) (40 Years) | GEOTHERMAL HIGH |
| 12,650,000,000 | $ Project Cost | 15,780,000,000 |
| 98,813,000,000 | kWh Sold | 98,813,000,000 |
| 12.80 | Average Cents/kWh With Royalty | 15.97 |
| | COMBINED CAPACITY (40 Years) | |
| 37,208,994,071 | $ Operating Revenue | 40,338,994,071 |
| 406,489,169,409 | kWh Sold | 406,489,169,409 |
| 9.15 | Average Cents/kWh | 9.92 |
| 1.72 | Cents/kWh Increase With Added Capacity | 2.49 |
| 23.2% | Cents/kWh % Increase With Added Capacity | 33.6% |

| | | |
|---|---|---|
| | EXISTING SYSTEM (1990) | |
| 10,757,280,000 | Total kWh Capacity | 10,757,280,000 |
| 8,264,379,327 | With 23% Reserve | 8,264,379,327 |
| 613,974,852 | $ Operating Revenue | 613,974,852 |
| 8,264,379,327 | Annual kWh Sold | 8,264,379,327 |
| 7.43 | Average Cents/kWh | 7.43 |
| SOLAR/OIL | ADDED CAPACITY (100MW PLANTS) (40 Years) | OIL |
| 10,610,000,000 | $ Project Cost | 8,570,000,000 |
| 98,112,000,000 | kWh Sold | 98,112,000,000 |
| 10.81 | Average Cents/kWh With Royalty | 8.73 |
| | COMBINED CAPACITY (40 Years) | |
| 35,168,994,071 | $ Operating Revenue | 33,128,994,071 |
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Exhibit J

# AN ASSESSMENT AND CRITIQUE OF:

# DEPARTMENT OF BUSINESS AND ECONOMIC DEVELOPMENT ECONOMIC FEASIBILITY ANALYSIS REGARDING THE HAWAII GEOTHERMAL/UNDERWATER CABLE PROJECT

*PREPARED BY CARL FREEDMAN*
*12/4/89*

## BACKGROUND

The State of Hawaii and the Hawaii Electric Company (HECO) are undertaking an aggressively accelerated program to develop 500 megawatts of geothermal electrical generating capacity on the Island of Hawaii in conjunction with a deep underwater and overland transmission system to transport the generated energy to the Island of Oahu. The Hawaii Department of Business and Economic Development (DBED) has taken a lead role in the promotion of this enterprise.

DBED has commissioned studies which provide the basis for its conclusions that the geothermal/cable Project is economically feasible. A preliminary study was published in April of 1986: "Alternative Approaches to the Legal, Institutional and Financial Aspects of Developing an Inter-Island Electrical Transmission System,." prepared by Gerald A. Sumida et al. Subsequently, a study was commissioned to address economic concerns more specifically: "Undersea Cable to Transmit Geothermal-Generated Electrical Energy from the Island of Hawaii to Oahu: Economic Feasibility," prepared by Decision Analysts Hawaii, Inc., published in February, 1988. This latter study (DAHI study) is the basis for the projected capital costs of the geothermal/cable Project of $ 1.7 billion.

The Hawaiian Electric Company (HECO) issued Requests for Proposals to private industrial consortia to solicit proposed schemes to build, finance and manage the geothermal/cable Project. Four or five consortia have responded with proposals which are being reviewed by HECO and a consulting firm. A condition in the request for proposals was that the projected delivered cost of energy to Oahu would be at or below HECO's avoided cost of energy.

According to DBED literature the project would be financed, built and owned by a private corporate entity (or entities.) The project owner would (according to DBED's interpretation) bear all of the financial risks of project cost overruns or generation and transmission problems. Revenues for the project would be provided by a contract with HECO, binding Heco to purchase power delivered by the project to Oahu.

## CONCERNS REGARDING PROJECT ECONOMICS AND FINANCING

According to the best published hopes of DBED and HECO the geothermal/cable project could be built, financed and operated without costs or risks to ratepayers or taxpayers above what it would cost to generate electrical energy with oil-fired facilities. Ignoring all of the environmental, social, archeological, health and aesthetic issues not addressed by current economic analyses, this would be a welcome reassurance to residents of the state regarding the vulnerability of their pocketbooks.

Careful analysis of the DAHI study, however, indicates that the projected costs of building and financing the geothermal/cable project have been substantially underestimated and improperly compared to HECO's avoided costs (see discussion below.) This raises concerns over the cost impacts to Hawaiian residents which are potentially enormous. The details regarding how the proposals solicited by HECO will be assessed and the particular language and terms included in any subsequent proposed contracts are of crucial importance.

(1) Will the proposals solicited by HECO indicate project costs greater than HECO's avoided costs? If so, will the project still be considered by HECO?

(2) Will the proposals solicited by HECO propose to meet avoided costs by transferring financial risks to ratepayers, taxpayers, or utility stockholders ?

(3) Will the proposals solicited by HECO incorporate low-ball bids in anticipation of later re-negotiation or litigation?

Ostensibly, according to intended planned contractual arrangements, the ratepayers are to be insulated from costs exceeding HECO's avoided costs. Much previous experience with over-budget and non-functional electrical generation projects on the mainland has demonstrated that this promise may be a costly illusion. Corporations that have invested billions of dollars in a generating project in response to requests by the State of Hawaii and HECO are not going to absorb large cost overruns without litigating the matter tooth and nail in the courts. Contracts arranged on the basis proposed by DBED are not likely to be enforceable.

It is of paramount importance for these reasons to insure that any contractual agreements made by HECO, the State of Hawaii, or project consortia be examined very carefully to insure that they are based upon sound and reasonable economic assumptions, or they may end up being economic disasters paid for by Hawaii's ratepayers and/or taxpayers. From an economic point of view, the proposed projects will only be successful if they are in fact, actually economically prudent, regardless of any contractual schemes or promises.

## ASSESSMENT OF DECISION ANALYSTS HAWAII STUDY

### OVERVIEW

Currently, DBED's economic projections of the economics of the geothermal/cable project are based upon the study by Decision Analysts Hawaii, Inc. published in February of 1988.

The study assumes that the cable and transmission system will be built and financed by one private corporate "venture" and that the geothermal wells and generation facilities will be built by another similar venture, perhaps under the ownership of a common larger corporation. Estimates are made of the costs of building the various components of the geothermal/cable project based upon other studies and by scaling costs from other projects. The study establishes schedules of year by year expenditures, revenues, and bond sales and payments. The schedules are discounted to present values and are compared with estimates of present values of HECO's avoided fuel, operating and capital costs. By various indicators of venture profitability, break-even fuel oil cost and cost to benefit ratios, the costs of the geothermal are evaluated as being economically feasible.

Though the study is rigorous in its treatment of cash flows and discounting methodologies, it makes some simple errors that are of significant consequence to the outcome of its conclusions. The study assumes 100% availability factors for geothermal generation and transmission. No transmission losses are accounted for. Assumptions are made regarding financing methodologies that are inconsistent with conventional experience and would not in certain instances be legal without legislative actions. Real generation capital cost escalation is ignored. Capital costs are in certain instances substantially underestimated. Certain methods of scaling generation plant capital costs are misapplied.

## GENERATION AND TRANSMISSION AVAILABILITY

The text of the DAHI study acknowledges that generation and transmission facilities will have some required maintenance and outage time. In the actual arithmetic of revenue calculations used in the study, however, no such adjustment is made. Revenues are calculated based upon 500 MW of power output for 8760 hours per year (100% availability.) The study states at one point in the text that each 25 MW geothermal generation plant will be built to 27.5 MW capacity to account for maintenance time, however, no such adjustment was actually made to the capital cost or operating expenses used in the calculations. The calculations used in the study assume 100% availability and 100% capacity factors for geothermal, transmission and AC-DC conversion facilities.

There is no such thing in the world of electrical power generation as a plant operating at 100% availability. Planned maintenance and unplanned outages are inevitable. Transmission system outage percentages are typically quite small, but would be additive to generation outage times. A 90% overall availability would be very optimistic for a geothermal/cable system. This statistic is important because it directly and proportionately effects the amount of energy delivered by the geothermal/cable system and the revenues accrued by the geothermal/cable ventures.

## TRANSMISSION LOSSES

*The DAHI study compares the costs of geothermal generation on* the Island of Hawaii to meet Oahu's needs with local generation on Oahu. Although the study mentions in its text that revenue calculations are based upon delivered energy to Oahu (rather than generated energy) there is no accounting of transmission losses anywhere in the actual calculations of revenue or generation costs. Revenue is calculated based upon delivering 500 MW of power to Oahu 100% of the time, generated by 500 MW of capacity on Hawaii. Transmission losses directly and proportionately effect the amount of delivered energy and accrued revenues of the geothermal/cable venture. Transmission losses are typically at least 10% for a system like the one proposed in this project.

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The DAHI study estimates the costs of a series of twenty power plants of 25 MW capacity. The costs for these plants are "scaled" from the documented costs of 12.5 MW plants. The concept used in scaling is that a larger plant is cheaper per MW because of the economy of scale. A boiler twice as big costs less than twice as much. The formula used in the DAHI study is the ".6 power" rule which is commonly used in scaling generation facility capital costs. According to this formula a 25 MW plant costs 51.6% more than a 12.5 MW plant. This is an appropriate application of scaling capital costs.

The DAHI study goes further than this, however. It groups the power plants into clusters of fours and reduces the costs of the second and forth plants in each group to 70% of the scaled cost and reduces the third plant to 80% of the scaled cost. The logic used is that the plants will be close enough together that they can share certain of their facilities and thus net cost savings. The net capital costs for the network of generating facilities is reduced by this treatment of costs to an average of 80% of the previously scaled costs. This treatment is not conventional. It is especially not appropriate in this instance because of other assumptions made in the analysis. In the section of the study that addresses risks due to geological hazards it is stressed that the plants are distributed widely to avoid damage to more than one plant at a time due to lave flows. This is a very sensitive assumption because it is the basis for conclusions made by the study that there would be no loss in system net output and no loss in revenues due to geologic hazards (a possible loss of one plant.) Grouping the plants close enough to benefit from economies of scale is not consistent with this assumption.

Additionally, the DAHI study uses the same .6 power rule to scale the capital costs of wellfield steam-gathering equipment as it uses to scale generation plant equipment. This is inappropriate. Steam-gathering equipment does not become less expensive per MW for a larger field than for a smaller one according to a .6 power rule. If anything, much of the costs per MW increase as wellfield size increases because of the longer average distances between each well and the power plant. A smaller power plant is located in a smaller wellfield and is consequently relatively close to the wells that supply it. As the size of a power plant increases, the size of the wellfield dedicated to the plant increases and the average distance of each well to the power plant increases. Steam-gathering piping costs increase as the average distance to the power plant increases. This principle dictates that the cost per MW for steam gathering piping <u>increases</u> as the size of the power plant increases. The DAHI study erroneously makes the opposite assumption and calculates the cost of a 25 MW steam-gathering system by <u>decreasing</u> the costs per MW of steam gathering equipment according to the .6 power rule from the documented costs for 12.5 MW plant equipment. Furthermore, the assumption noted above that plants will be grouped in clusters of four closely enough to benefit from economies of scale would further aggravate the need for even longer and consequently more expensive steam-gathering equipment.

## WELLFIELD COSTS

Perhaps the most sensitive single set of assumptions regarding the costs of the geothermal/cable venture are the estimates of the costs of drilling a productive wellfield. Approximately one third of the total project costs are in the wellfield. The primary factor effecting wellfield costs is the number of wells necessary to develop the required thermal energy for generation purposes. Some of the wells drilled would be productive. Some would be used for fluid re-injection. Some would be dry, or too hot or cool. Some would need to be replaced over the life of the facility. The DAHI study assumes that 13 wells, plus eight replacement wells, will be required for each 25 MW plant. This equates to useable/non-useable ratio of 5:1. This ratio may be very optimistic for Hawaii geology.

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Without much experience with Hawaiian geology, predicting the productivity and success rate of wells is quite conjectural. The wellfield success rate assumed in the DAHI study is perhaps possible, but must certainly be categorized as quite optimistic. These assumptions effect the certainty of any economic predictions dramatically.

## CAPITAL COST ESTIMATES

The DAHI study is consistently optimistic about estimates of capital costs. The cost estimate for AC-DC conversion stations, for example, is \$ 72 million. According to current estimates from B.C. Hydro, the costs would be \$250 per KW for each station, totalling \$ 250 million. The DAHI cost estimate for the entire transmission system including the underwater cables, overhead lines, pumping stations and AC-DC conversion station is $ 413.3 million.

The geothermal/cable project incorporates several aspects of new unproven technologies in new untried areas of geological and geographical extremes. Even in conventional projects of this magnitude it is prudent for planning purposes to include contingency costs to include what is more a probability than a possibility of project delays, technical problems and cost overruns. No such contingencies are considered by the study.

## REAL COST ESCALATION

In order to calculate HECO's future avoided costs DAHI escalates the real cost of fuel oil according to the average of a series of estimates of future oil prices. The real escalation of fuel prices is substantial. (Real cost escalation is the increase over and above that due to inflation.) These avoided fuel costs are compared directly with various costs of geothermal generation. The study does not make the appropriate analogous accounting of the real cost escalation of plant capital costs. (Geothermal generation costs are primarily capital costs.) Historical experience indicates that real plant capital costs escalate faster than real fuel prices during periods of real fuel price increases. Utility planners know, for example, that their older plants were less expensive to build than their newer plants, even in terms of real costs. (This may not be true in operating or fuel costs, however.) Because the DAHI study is comparative in nature, the differences in the treatment of cost escalation skew the results in favor of the geothermal/cable venture.

## FINANCING

The DAHI study assumes that the cable and transmission system will be financed with Hawaii Special Purpose Revenue Bonds (Industrial Development Bonds) at a rate .5% above municipal bond rates. The geothermal venture is assumed to float bonds at .5% above the Aaa corporate rate. At the same time the study maintains that all financial risks due to cost over-runs or resource failure are to be borne by these financing sources. These are clearly not realistic assumptions.

The issuance of Hawaii Special Purpose Revenue Bonds for the cable project would require special action by the Hawaii State Legislature.

The assumption that the geothermal/cable venture can be financed by bonds issued at such low interest rates with such a substantial assumption of risk is inappropriate, especially in a comparative study of this nature. The costs of financing appreciably effect the profitability equation used in the DAHI study.

## SENSITIVITY ANALYSIS

Throughout the DAHI study estimates and calculated numbers are associated with standard deviations to imply confidence intervals around the predicted statistics. This sort of analysis has its place in the laboratory, in demographics and perhaps around casino gambling tables. The use of confidence intervals in a study of this nature which is designed to be used by policy decision-makers is inappropriate and misleading. To a person familiar with statistics these numbers may be of some value, but to imply to a decision-maker who may rely on the study that the values ascribed to the confidence intervals are realistic indicators of the possibility of error of the study is ludicrous.

Even from a purely statistical viewpoint the sensitivity analysis is misapplied. This type of analysis is only appropriate when all of the input parameters are truly independent of one another and are normally distributed. Neither of these conditions are met in a construction project where delays in one portion of the project can effect scheduling and costs of other portions and where the potential for cost overruns exceed the margin of potential cost savings.

Furthermore, the sensitivity analysis only takes into account one particular type of error. It ignores the types of errors noted above, which are incremental, but when taken as a whole substantially effect the outcome of the analysis. The omission by the DAHI study of any consideration of transmission losses and availability factors effects the overall calculations in the cost comparison by at least 21%, and depending on actual achieved availability factors, perhaps by 46% or more.

Approximate percentage impacts to the DAHI study projected costs are listed below to give some idea of the magnitude of their importance. These numbers are not intended as correction factors to adjust the DAHI study results to draw more accurate conclusions. They are included here to demonstrate the sensitivity of the DAHI study to its own oversights and biases. All figures are percentages of the total geothermal/cable project costs/revenues.

The cumulative percentage statistics below are only for order-of-magnitude comparison purposes. The high-end statistics may include some double-counting as, for example, in the case of generation availability being improved by additional wellfield improvements.

| | |
|---|---|
| GENERATION/TRANSMISSION AVAILABILITY | 10 - 30% |
| TRANSMISSION LOSSES | 10 - 12% |
| CLUSTERING CAPITAL COST REDUCTIONS | 6% |
| SCALING STEAM-GATHERING SYSTEM | 6% |
| WELLFIELD COSTS - (AS IN ICELAND) | 10 - 20% |
| CONVERTER STATION ACTUAL COSTS | 8% |
| CAPITAL COST ESCALATION | 4% |
| FINANCING BOND RATES | 5 - 10% |
| CUMULATIVE | 76 - 143% |

These statistics indicate that the DAHI study includes errors and oversights that substantially effect the outcome of its conclusions, well in excess of the confidence intervals implied in its sensitivity analysis.

## CONCLUSIONS

The proposed geothermal/cable project is a very large and expensive project with an enormous potential to impact the economy of the State of Hawaii. Currently existing economic analyses do not establish a sound basis for confidence in the ultimate cost-effectiveness of the project. Very careful scrutiny must be given to the details of proposed project bids and contractual arrangements to assure that financial risks and the costs of project failures or overruns will not be assumed by Hawaii's ratepayers or taxpayers or HECO's stockholders.

Exhibit G

Exhibit J

# APPENDIX A

# GEOTHERMAL RESOURCES OF THE KILAUEA EAST RIFT ZONE

Prepared from Public Records
by

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## APPENDIX A

## GEOTHERMAL RESOURCES OF THE KILAUEA EAST RIFT ZONE

### A.1 HAWAIIAN ISLANDS - ORIGIN AND ACTIVITY

The island of Hawaii is the newest member of a chain of volcanoes that have repeatedly matured as major islands in the middle of the northern Pacific Ocean. An obscure complex of processes is generating inordinate quantities of magma in a deep earth phenomena, the mantle plume or mantle hot spot. Within the plume, at depths of 60 kilometers and more, the Hawaiian basaltic magma (tholeiite) forms at temperatures of 1350 to 1400°C. These high temperatures impart an extreme fluidity and density reduction to the magma. The upward mass movement of magma easily penetrates the relatively thin oceanic crustal plate and rapidly constructs new volcanoes on the deep ocean floor (Decker, 1987).

The Hawaiian mantle hot spot, fixed in position and operating as an energy and mass transfer system for more than 70 million years, is undeterred by the steady northwestward movement of the Pacific crustal plate above it. This plate movement has preserved a trail of older volcanoes and seamounts, The Hawaiian-Emperor Volcanic Chain, which courses straight and west-northwest for 3550 kilometers. After a 60° right bend, the chain holds a straight, north-northwest course for an additional 2600 kilometers before its destruction, with the Pacific crustal plate, by subduction in the Aleutian Trench. The 3550 kilometer distance between currently active volcanic centers (southeastern island of Hawaii) and the bend represents 44 million years (my) of relatively continuous and increasing magma production by the Hawaiian hot spot. The volcanic rock produced, an approximate volume of 750,000 cubic kilometers, now stands on the seafloor as the long, linear Hawaiian Ridge. The potassium-argon age dates of lava rocks in the State of Hawaii range from 5.7 to 5.4 my, respectively, on Nihau and Kauai, to 0.375 - 0.4 my at Mauna Kea and Mauna Loa, the giant shield volcanoes on Hawaii. Volcanic growth studies indicate that the Hawaiian hot spot is presently generating lava volumes at the greatest eruptive rates in its known history (Clague & Dalrymple, 1987).

The island of Hawaii is one of the largest volcanic mountains on the earth. It is a composite structure of five volcanic centers including the two mighty shield volcanoes Mauna Kea and Mauna Loa. Often snow covered, these two young peaks stand nearly 4200 meters above sea level and nearly 9700 meters above the ocean floor in the Hawaiian Trough, a submarine basin northeast of the island. The island's land area of 10,438 square kilometers has maximum dimensions of 150 kilometers N-S and 129 kilometers W-E. Only 11 percent of the total volcanic rock mass rises above sea level. Initial lava eruptions on the ocean floor constructed volcanic seamounts, probably first broaching sequentially as separate islands, then rapidly coalescing to form the large, young, present island of Hawaii.

The five volcanic centers on the island of Hawaii, in sequence of diminishing age, are Kohala, Mauna Kea, Hualalai, Mauna Loa and Kilauea. The southeastward trends of increasing youth, volcanic activity and seismicity are even more evident with the inclusion of the active volcanic seamount, Loihi, 50 kilometers south of Kilauea's summit caldera with its summit 970 meters below sea level (see Figure A-1 and Malahoff, 1987). Table A-1 presents key information on the ages and sequence of volcanic activity at these six centers.

The magma and lava processes, now operating in their upper dynamic ranges at Kilauea, repeat the distinctive, comprehensible style of Hawaiian volcanism. Compared to the worldwide explosive volcanic events common to both geologic and human history, Hawaiian volcanism is reasonably well mannered and approachable. This was implicit in the action of Thomas A. Jagger, (1871-1953) a Massachusetts Institute of Technology professor, who established in 1912 the initial scientific facility that was to become the Hawaiian Volcano Observatory (HVO), at the summit of Kilauea. HVO has gathered and interpreted an extraordinary body of knowledge about the mobile magmas and lava that continue to build Kilauea and the Hawaiian volcanic chain in the mid Pacific. The U.S. Geological Survey (USGS), having staffed HVO since 1947, has led this scientific achievement. In 1987, marking the 75th anniversary of HVO, the USGS published a large, two volume compendium entitled Volcanism in Hawaii, Professional Paper 1350 (Decker, et al., 1987). There was no intent to examine the geothermal energy potential of Kilauea amidst the many scientific objectives of this excellent collection of papers. However, the papers in Professional Paper 1350 are important supplements to a thin geothermal drilling and production data base for any evaluation of the geothermal resource which exists in the East Rift Zone of Kilauea. (Professional Paper 1350 may be examined or purchased at the Earth Science Information Center, USGS, 504 Custom House, 555 Battery Street, San Francisco, CA 94111. Telephone 415-556-5627.

The vertical magma conduit under the summit of the Kilauea volcano is the central feature of a vigorous construction process. A catalog of 70,000 earthquakes, collected by HVO since 1962, reveals in substantial detail the active processes of magma transport within Kilauea's structures (Klein, et al., 1987). Long period earthquakes trace both conduits and magma bodies rising from 60 kilometers depths to a shallow magma reservoir between 3 and 7 kilometers below the summit caldera floor. The reservoir is aseismic because it stores a relatively large mass of hot liquid charges of rising magma until an eruptive event is initiated at the summit or the magma moves laterally into linear rift zones for further underground distribution. The openings into Kilauea's two active rift zones are near the upper limit of its summit magma reservoir. The solid roof of both the reservoir and the lateral conduits show varying levels of seismicity which reflects magma mass and transport at greater depth. The long linear rift zones, radiating from the summit reservoir, effect a fundamental, horizontal, internal distribution of magma away from a volcanic center. A tensional stress field, across the rift zone, facilitates magma emplacement commonly driven downrift by the hydrostatic head gained from its brief residence in the summit reservoir.

The Hawaiian volcanic rift zones are created as the roofs and surface expression of active deep magma conduits. Both transient and locally stored magma masses establish an abundance of thermal energy. Specifically, it is the repetitive process of magma emplacement as near vertical dikes in the tensioned roof rock which creates the heat source for a geothermal resource potential in an active rift zone. The Kilauea East Rift Zone (KERZ) is in a vigorous stage of growth with a geologically optimal level of internal magma activity. It is flanked by an abundant groundwater regime on the north and by the sea on the south. The junction of abundant heat and fluids along the KERZ establishes its unique geothermal resource potential.

## A.2 KILAUEA EAST RIFT ZONE AND ITS GEOTHERMAL RESOURCE POTENTIAL

The topographic form of the KERZ, after its gradual emergence from Kilauea's gentle summit rise, is that of a broad, linear ridge. The ridge crest courses east-northeast and straight for 42 kilometers, from an elevation of 880 meters at Makaopuhi Crater to sea level at Cape Kumukahi (see Figure A-2). Beyond the Cape, the submarine element of the KERZ carries the same straight course for an additional 70 kilometers to termination on the ocean floor at an approximate depth of 4,800 meters. The entire structure, subaerial and submarine, was built rapidly by repeated rift crest lava eruptions supplied by magma transport in the underlying conduit. In the middle of the subaerial element the lava apron has a maximum topographic width of 18 kilometers measured normal to the rift axis. The more significant feature of the KERZ is the crestal band of local volcanic cones, craters, linear fissures and graben fault structures that reflect the crestal, cross rift, tensional stress above the deep magma conduit. The surface width of this active band is approximately 3 kilometers.

In 1976, at a location approximately 10.5 kilometers uprift from Cape Kumukahi and on the active crest of the KERZ, the initial geothermal test well, HGP-A, was drilled to a total depth of 1966 meters. A bottom hole temperature of 358°C was encountered and a total mass flow rate of 110,000 pounds per hour, 43 percent steam and 57 percent liquid, was measured. Following installation of a 3 MW turbine generator in March 1982, the steam production of this initial well has provided electric power in the range of 2.8 to 2 MW. Except for scheduled overhauls, this small geothermal power plant has operated continuously for seven years with an availability factor of approximately 90 percent. The geothermal fluid and electrical production from this single well and plant, now called the HGP-A Generator Facility, is discussed in more detail in Section A.5. This achievement provides the most meaningful indication of an exploitable geothermal resource in the KERZ.

The internal fabric of fast-building Hawaiian rift zones is a nearly horizontal, planar sequence of submarine and subaerial lava flows. These basaltic flows originate from local volcanic vents or parallel linear fissures situated along the rift crest overlying the deep magma conduit. In the upper part of the KERZ the top of the magma conduit appears to be shallower (seismicity to 2-3 kilometers) and consistently open (deeper aseismic zone) as discussed in Hardee, 1987. The continuous lava eruption which began in January 1983 in the upper KERZ, is now venting from a newly constructed volcanic cone, C48, at a point approximately 10 kilometers down rift from Makaopuhi Crater. The lava flows are spilling southeastward and into the sea between Kupapau and Hakuma Points.

In the lower 30 kilometers of the KERZ the top of the magma conduit appears to be deeper (about 3.4 kilometers or more) and more commonly closed. Here, the advancing magma reopens conduits by the hydraulic injection capability of its significant fluid pressure. The existing host rock is penetrated by the mobile fluid magma in nearly vertical planar sheets, several feet thick. Both thermal energy and high temperatures are maintained by repetitive dike intrusion and solidification. This dike building process is facilitated by the tensional stress imposed on the rift crest, from magma conduit depths to the surface, by earthquakes, normal faulting and slumping of the seaward south flank of the KERZ. Dike emplacement in the lower KERZ efficiently transfers high heat quantities from magma to shallower prospective geothermal reservoir intervals, as shown in Figure A-3.

Because Hawaii geothermal drilling records, required to be filed with the State of Hawaii Department of Land and Natural Resources (DLNR), are reported in English units, the following discussion will utilize the same. The productive geothermal well HGP-A has a 7 inch perforated liner completion in the depth interval between 2920 and 6450 feet. This interval of submarine lava flows and younger intrusive dike rock presented a temperature profile that increased to approximately 620°F at 4000 feet, decreased to about 570°F at 5800 feet and increased to a maximum 676°F at 6450-foot total depth (see Figure A-4). The selection of the top of the geothermal reservoir (and completion) interval in this first well seems debatable. A restriction in the liner, just above 4000 feet, unfortunately precludes a spinner evaluation of the deep fluid entries in HGP-A. Aside from these concerns, this well continues to produce geothermal reservoir fluids with little decline since it was put into production in December 1981.

Puna Geothermal Venture (PGV) during 1981-85 drilled three offset wells (about 1800 and 3500 feet away from HGP-A well). In a publicly distributed November 1987 Environmental Impact Statement (EIS) for a proposed 25 MW (net) geothermal power plant and wellfield, PGV states the geothermal reservoir extends below 4000 feet. PGV bottomed these offset wells at total depths between 7300 and 8000 feet. The EIS briefly characterizes the geothermal reservoir as "very high temperature (over 600°F), two-phase (vapor-liquid)". Higher steam fractions were obtained in all PGV initial flow tests than the 43 percent steam fraction long prevailing in the HGP-A well production. From these four wells which have produced or tested geothermal fluids, the geothermal resource, in the Kapoho locale of the lower KERZ, is a 600°F, two-phase regime at moderate depth. Three additional exploratory geothermal wells drilled along the south edge of the KERZ crestal structure have encountered encouraging temperatures but have not demonstrated fluid yielding reservoir intervals by flow tests. These seven deep geothermal wells are discussed in more detail in Section A.5 following.

DLNR, under its published Rules on Leasing and Drilling of Geothermal Resources, requires the filing of certain well reports (S13-183-85) following completion of drilling operations on any geothermal well. After an initial period of confidential status, these well records are opened to public access. The reports of all seven of the geothermal wells drilled in the lower KERZ may now be copied or examined at the public document room. Significant documents include well drilling and completion histories, lithologic and temperature logs, some geophysical logs and water sample analyses.

A hypothetical geothermal reservoir would be expected to be located in the tension stressed, fractured rock below the crestal band of the KERZ as shown in cross section in Figure A-5. The moderately deep vertical extent of the reservoir would be positioned in the hot diked roof above a deeper bundle of magma conduits or a possible static magma body. Penetrations of copious supplies of fresh groundwater, and of seawater to a lesser extent, would enter at depth from opposing boundaries of the fractured reservoir to mix in an internal convection cell with a base temperature of 600°F. The cross rift and long rift extent and the specific nature of the effective side boundaries of the hypothetical reservoir have yet to be determined. Drilling along the south flank of the KERZ crest suggests that sharp vertical boundaries exist there.

Subsurface supplies of waters that would contribute to KERZ geothermal regimes are inferred to be large. The two shield volcanoes, Mauna Kea and Mauna Loa draw heavy precipitation from the northeast trade winds. Annual rainfall of 100 to 125 inches is received on the lower slopes of Mauna Loa and the crest of the KERZ. Practically all of this sinks into the porous surface lavas and this meteoric water infiltration has established a very large ground-water body along the whole north flank of the KERZ. A limitless supply of seawater can infiltrate the entire narrow southern flank.

In spite of the paucity of specific hydrologic subsurface data, several early findings suggest that interactions between groundwater, geothermal fluids and seawater will be intricate. A small group of private water wells, drilled on the lower KERZ before its geothermal potential was perceived, were never utilized because of the poor quality of the abundant shallow groundwater found. This has recently been identified as natural degradation caused by leakage from the now proven geothermal reservoir (Iovenitti, 1987). In the produced liquid fraction from the HGP-A well, the sodium to chloride ratio within the steadily increasing total dissolved solids content indicates seawater intrusion into the geothermal reservoir. A preliminary working concept of large fresh water and seawater supplies aggressively penetrating the prospective geothermal core of the KERZ and contributing to the hot fluid convection is sketched in Figure A-5.

## A.3 LEGAL STATUS AND REGULATION OF GEOTHERMAL RESOURCES

Ownership of geothermal resources is claimed by the State of Hawaii under state lands and under Reserved lands. The latter are lands owned or leased by any person in which the State or its predecessors in interest has reserved to itself, expressly or by implication, the minerals or right to mine minerals, or both. Most private land ownerships in the KERZ are Reserved lands. Certain private land owners may eventually choose to test in the courts the State's claim to geothermal resource ownership related to the Reserved land concept. All geothermal resource development commonly will require dual leases on the Reserved land tracts to be utilized. A geothermal mining lease must be obtained from the State for the subsurface rights to the geothermal resource and a lease must be obtained from the landowner for surface access and utilization. DLNR administers geothermal leasing and drilling under rules in Title 13, Chapter 183, which were approved in June 1981. Key State geothermal leasing provisions are royalties of 10 to 20 percent on resources produced, sold, or utilized. When necessary to initiate or continue commercial production of geothermal resources, the State Board of Land and Natural Resources (BLNR) is authorized to waive royalty payments to the State for any period up to eight years. Ten year primary terms of leases are extendable to a total of 65 years. Individual lease tracts are limited to 5000 acres of contiguous lands. State lands are leased by public auction only, and Reserved lands are leased by grant to the landowner or by auction. Hawaiian land ownership tracts, highly varied in size and in shape, are legally represented by Tax Key Maps. Land corner monuments and surveys of the highly varied tracts have not been commonly utilized.

Hawaii has stringent land use laws (see Hawaii Revised Statutes 205) which, when enacted, did not address geothermal resource utilizations. The BLNR and the counties jointly establish and regulate land use districts which are dedicated to urban, rural, agricultural and conservation uses. In 1984, state regulations were amended to enable geothermal development in all land use districts provided a Geothermal Resource Subzone (GRS) was first established by procedures under Title 13, Chapter 184. The BLNR was given the authority to designate and regulate GRS. Three GRS were approved and established in the KERZ as shown in Figure A-6. The total amount of lands included are approximately 21,900 acres apportioned among three blocks as follows:

| | |
|---|---|
| Kilauea Lower East Rift (Kapaho Section) | 7,353 acres |
| Kilauea Lower East Rift (Kamaili Section) | 5,531 acres |
| Kilauea Middle East Rift | 9,014 acres |

Geothermal development may proceed only within such designated GRS areas. Proposed designations of new GRS may be initiated by the BLNR, any landowner, geothermal lessee or lease applicant, as can proposed modifications and withdrawals of existing GRS. Environmental impact statements are not required in designating, modifying or withdrawing any GRS. The GRS process has structured the deliberations about possible geothermal resource utilizations and has interfaced the county and state authorities within designated GRS areas of the KERZ. Hawaii County is the lead authority if exploration or development is proposed on rural and agricultural lands within the GRS. DLNR is the lead authority on conservation lands within the GRS. It must be noted that public input to the GRS process is significant. Until the value of geothermal enterprise is more clearly demonstrated, resistance to GRS enlargement in the KERZ is expected.

The approval paths for exploratory geothermal drilling on dual surface and subsurface (state) leases within GRS are briefly cited here because this is the critical, near term activity required in the KERZ. Permit requirements in the Geothermal Resource Subzones are detailed in Appendix B. On agricultural and rural lands a Geothermal Resource Permit (special use permit) must be approved under Rule 12 by the Hawaii County Planning Commission. On conservation lands, a Plan of Operation and a Conservation District Use Permit must be approved by DLNR. Individual drilling permits for each proposed geothermal well are required from DLNR regardless of the land use classification of the drillsite.

## A.4 AVAILABILITY AND ACCESSIBILITY; PROSPECTIVE AREAS

The three designated GRS areas in the lower KERZ cover a substantial portion of the prospective crestal trend which extends for approximately 30 kilometers between the C48 erupting volcanic vent and Cape Kumukahi. DLNR records of issued geothermal mining leases and applications for lease now cover a substantial portion of the GRS areas. Several of the large landowners in the KERZ are lessees under issued geothermal mining leases. Kapoho Land and Development Company, Bishop Estate and the Campbell Estate are landowners with geothermal leases or applications dedicated to existing exploration or development agreements with certain geothermal operators. Other privately owned land tracts within the GRS areas are, or may be, under lease or option agreements with geothermal operators. Such leases may or may not coincide with issued mining leases and may or may not be disclosed in public records.

HECO and its consultants made no inquiries or evaluations of landowner and leaseholder positions in contemplating or structuring this RFP. Landowners, leaseholders and geothermal operators positioned in the KERZ will determine their individual responses to this RFP. Proposers are cautioned that they proceed at their full risk in evaluating and responding to the status of lands and leases in the KERZ.

Off-road accessibility in most of the KERZ terrain is difficult to impossible, even for four wheel drive vehicles. Dense undergrowth, forest cover and impassable lava rock surfaces are typical barriers. Most private land tracts are fenced or posted against trespassing. New road construction approvals for geothermal development will be keyed to the status of the land traversed: agricultural, rural or conservation.

## A.5 ELECTRIC GENERATION AND RESOURCE PRODUCTION IN THE KERZ

The 3 MW power plant of the HGP-A Generator Facility was constructed in 1981 with funds jointly provided by the U.S. Department of Energy, the State and the County of Hawaii. A profile of the plant's electric generation history is shown in Figure A-7 for the seven year interval, commencing in March 1982, of commercial power delivery to Hawaii Electric Light Company. Because of economic constraints, detailed well production records were not accumulated. Possible declines in wellbore deliverability or reservoir performance might be inferred from generator outputs; an initial peak output of 2.8 MW versus 2.45 MW currently suggest a 1.8 percent annual decline in well production. Although several scheduled overhauls were made without finding serious degradation, certain material and equipment deficiencies in plant design have been clearly demonstrated and may be registered in the output decline. Cumulative silica scaling in the HGP-A wellbore may be a contributing cause of the apparent decline. Several very informative studies of plant and well performance have been completed and documented in recent years by Donald Thomas of the Hawaii Insitute of Geophysics.

The continuous 7-year geothermal fluid production of the HGP-A well has been very successfully utilized. However, it has afforded only a meager basis for understanding the geothermal resource. The lack of detailed records of fluid production parameters, of periodic pressure-temperature-spinner surveys over the well's 3530-foot perforated liner completion interval and of reservoir pressure monitoring in any offset observation hole are to be noted. This provides little context within which several perceptive and thorough studies of produced fluids chemistry can be conclusively judged (Thomas 1985a and 1987).

The total mass flow of HGP-A well, measured initially as approximately 47,300 pounds per hour steam and 62,700 pounds per hour liquid, is a product of wellbore mixing (inside 7 inch production casing) of different fluids from multiple, separate entry points of imprecise depths, pressures and temperatures. The distinctive, low salinity of the first produced liquid, suggestive of a meteoric water dominance in the geothermal reservoir, was lost in a gradual, four-year increase in salinity, to about 15,000 mg/kg of NaCl, with production for electric generation. The Na and Cl ionic ratios and other metallic changes seem to prove a seawater intrusion into HGP-A well's production sink. This fluid change to a new high but stable, level of salinity appears to confirm the implications of an irregular presence of anhydrite filled fractures amidst other alteration minerals found in the HGP-A rock cores from the reservoir interval. Fracture guided intrusions of seawater into the geothermal fluid convection cells must repeatedly occur. However, these intrusions individually are probably limited in duration and volume because of rapid self-sealing by new mineral deposition at the seawater-geothermal fluid interface. A diminution of pH from 7.6 to 6.5, attending the increase in salinity of produced brines, was measured. Possible minor decreases in produced steam fraction and wellhead temperature, if suspected from time to time in short term flow variations, have not been measured to identify any long term trend. The precisely identified stability of the silica content of the brine (about 800 mg/kg) and of the low content of non-condensible gas (0.3 percent by weight) in the steam phase reflect the apparent stability of the total mass flow produced by the HGP-A well since December 1981.

Key information from the seven deep geothermal wells drilled into the geothermal reservoir, or equivalent depths, in the lower KERZ is summarized in Table A-2. Their locations are shown on Figure A-6.

Key features of the wells which penetrated the geothermal reservoir were 9 5/8 inch production casing (cemented just below 4000-feet in KS wells) and 7 inch perforated liner in an 8 1/2 inch hole to total depth. It should be noted that both HGP-A and KS-1 wells include remedial 7 inch casing inserts that were emplaced before production and testing. The KS 1 and 2 tests support the recent conclusion (Thomas, 1987) that a dry steam producing zone exists in the HGP-A well. Composite chemical data from the four wells tested are presented in Tables A-3 and A-4.

Final Hawaii County approvals are being sought for the Geothermal Resource Permit for the PGV's proposed 25 MW (net) geothermal plant and wellfield which expectedly will include KS-1A and 2 wells in production service. Drilling plans for the required additional production and injection well are in preparation for a commencement of development operations later in 1989.

A proposed Scientific Observation Hole Program at additional locations within the GRS areas along the lower KERZ is planned. The intended slim hole drilling program, utilizing both rotary and diamond core procedures, is jointly funded by the State of Hawaii and geothermal operators (Geothermal Resources Council Bulletin, 1988). Information from the intended 4000-foot holes is to be promptly released to the public domain and should be available during the negotiation period for the Power Purchase Agreement.

## A.6 GEOTHERMAL RESERVOIR POTENTIAL IN THE KERZ

The geothermal reservoir potential of the KERZ is most strongly supported by the HGP-A Generator Facility performance combined with its position above a magma conduit which is reasonably defined as to location and function. The critical concern is an estimate of the magnitude of this reservoir potential within the lower KERZ between the C48 vent and Cape Kumakahi (30 kilometers or 18.6 miles).

Volcanic eruptive history proves recurring magma transport through the entire lower KERZ. Significant lava eruptions from Heiheiahulu "in the reign of Arapai" - circa 1750 A.D. (vent is 22 kilometers SW of Cape Kumakahi) and the Kapoho eruptions of 1955 and 1960 obtain importance against a detailed modern study of Kilauea's magma balance. The USGS - HVO concludes that nearly 50 percent of all magma mass remains below ground, being emplaced as intrusive dikes and sills. The entire KERZ has become a more favored structure for magma distribution and dike construction since the magnitude 7.2 Kalapana earthquake of 1975 which tensionally opened the entire KERZ structure by seaward slumping of its south flank, as shown in Figure A-8 and discussed by Lipman, et al., 1987. A preliminary estimate, made from deflations of Kilauea's summit following the 1975 quake, was that 3 million cubic meters per month of magma was moving into the rift zones. The deep fracturing in the KERZ consequent to this major earthquake should enlarge or maintain reservoir permeability and new meteoric and seawater inputs to geothermal fluid convection cells. Heat, fractures and fluids are renewed in the dynamic, continuous structure above the KERZ magma conduit.

The 500 MW objective of this RFP is based on market considerations (Lesperance, 1988, and Department of Business and Economic Development, 1989). No integrated study exists of all the KERZ geoscientific and well data that would provide a creditable estimate of the total geothermal potential. Only additional drilling, flow testing and production can provide measures of the energy capacity that is indicated to exist in the GRS of the KERZ. It is of some interest to note that one existing developer intends to utilize a 500 acre land area dedicated to its 25 MW (net) generation capacity. This suggests that the 22,000 acres within the three GRS areas, if only 50 percent productive, could yield 550 MW of capacity.

## A.7 GASEOUS AND LIQUID WASTE DISPOSAL FROM GEOTHERMAL WELLFIELD ACTIVITIES

Effluent waste disposal from the producing HGP-A well has not been managed in a way that is acceptable for future geothermal development in the KERZ. The 57 percent brine fraction, carrying about 15,000 mg/kg of NaCl and 800 mg/kg of $SiO_2$, is discharged to shallow surface ponds for percolation into the ground. The attending silica deposition eventually precludes percolation and new ponded areas are then utilized. This practice is unacceptable for the future commercial development that will occur along the KERZ. The produced non-condensible gas (NCG) is burdened with about 850 mg/kg of $H_2S$. Normal plant operation produces 1100 pounds per day of $H_2S$ that is now abated, with reasonable reliability, with NaOH in a two stage scrubber and by incineration. The $H_2S$ abatement experience at HGP-A, although costly and problem-plagued, provides notice that reliability, reserve capacity and alternate options of $H_2S$ mitigation will be essential to successful "good neighbor" geothermal development in the KERZ. It is appropriate to note that PGV's Amended Application for Geothermal Resources Permit for 25 MW (net) Plant and Wellfield (December 1988 submittal to Hawaii County Planning Department) proposes the injection of recombined streams of brine, condensate and NCG back into the geothermal reservoir. Just such recombined fluid injection reportedly is successful in its first year of utilization in the Coso geothermal field in California.

The present status of $H_2S$ emission controls, regarding geothermal development in the KERZ, merits special attention. A 1982-1983 State survey of $H_2S$ levels in a 27 station KERZ grid was completed, as were local surveys by HGP-A and PGV. These surveys should provide some insight into natural $H_2S$ emissions from continuous volcanic gas venting that proceeds between the obvious eruptive events. Aside from this singular feature of the KERZ, the Hawaii Department of Health (DOH), as the State regulatory authority, is now proposing a statewide ambient 1-hour emission standard of 139 micrograms $H_2S$ per cubic meter (0.1 ppmv) for inclusion in Administrative Rules Chapter 11-59. DOH also proposes a statewide allowable increment of 0.35 $mg/m^3$ (0.35 ppmv) of $H_2S$ emission from any new facility. This proposal and lesser $H_2S$ constraints are included in draft DOH Rules 11-60-15 and 16.

An additional DOH regulatory authority extends statewide to underground injection control (UIC). Though the non-potable quality of ground water was proven by landowner drilling in the KERZ before recognition of the geothermal resource, some of the GRS areas remain in the Underground Sources of Drinking Water (USDW) status. Injection of produced geothermal fluids will require approval by the DOH.

## A.8 VOLCANIC AND SEISMIC IMPACTS ON WELLFIELD DEVELOPMENT

An excellent summary of the volcanic hazards that occur along the KERZ is presented by Mullineaux, et al. 1987. Lava flows will pose the most likely hazard over time, as shown in Figure A-9. However, lava flows are controlled by topography, as any surface water flow would be. A careful evaluation of the KERZ terrain can be made with the assistance of detailed topographic maps recently published by the USGS (1:24,000 scale and 20-foot contour interval). The probable flow course and other possible topographic controls can be reasonably predicted. The morphology and emplacement dynamics of the blocky aa type of lava flow are detailed by Lipman and Banks, 1987. This more viscous, thicker building flow commonly moves in a 100-200 meter frontal width, several meters high and at velocities up to 50 meters per hour. Final flow thickness may range from 5 to 10 meters in height.

The less likely but more serious volcanic hazard, the fissure or vent eruption site event, is mitigated by the much smaller area of direct impact. However, against the expected long life of the geothermal resource it cannot be considered predictable in time or location. It will remain the greatest risk in development of the geothermal resources of the KERZ. Air lofted tephra (rock debris) ash and gas concentrations from eruptions may yield a range of secondary and addressable impacts on any KERZ geothermal site depending on wind conditions and distance from source points. Ground surface dilation, extension or subsidence due to local magma movements or lava discharges, are additional processes common in the KERZ that are of minor impact on wellfield operations.

The high seismicity of the KERZ is directly correlated with its high level of constructional volcanic activity. This is clearly presented in an excellent new map publication of statewide scope: "Seismicity of Hawaii, 1962-1985, USGS Open File Report 88-285" which may be purchased at the Pacific Map Center, 647 Auahi Street, Honolulu, HI 96813, Telephone 808-531-3800. The seismicity of Kilauea's magma system, detailed by Klein, et al., 1987, chiefly includes events of less than magnitude 4 which are generated by magma and dike activity in the 2-5 kilometers depth interval. This class of seismicity presents a significant guide for geothermal wellfield development and presents little or no attendant hazards. It is the deep, infrequent, tectonic earthquakes of magnitudes ± 7 which could impact KERZ geothermal development. Fortunately, the largest historical earthquake in this class, the November 1975 magnitude 7.2 event, at a depth of 9 kilometers under Kalapana on the southeast coast of the Island of

Hawaii, was fully recorded by the HVO seismic network. This imposed a 0.22 gravity acceleration measured at Hilo (43 kilometers NNW of Kalapana). Geothermal wells in the KERZ, with multiple cemented casing strings and Series 900 wellheads, spider braced in reinforced concrete cellars, should surpass the 0.4 gravity acceleration factor selected for the plant and surface facility design to safely withstand the tectonic class of earthquake.

Significant strategies can be utilized for the protection of KERZ geothermal wellfield development and production operations. Directional drilling would permit wellheads to be clustered on elevated or cinder berm protected wellpads that would be at minimal risk from both volcanic and the seismic hazards. Drilling rigs may merit heavier guy-lines as added protection. Steam and other wellfield pipelines will be vulnerable to lava flows and to major earthquakes. Rapid cinder berm construction and pipeline repair capacities can be considered as response options.

The common volcanic-seismic basis of both the resource and hazards in the KERZ should encourage development of key surveillance methods. A very sensitive seismic net could simultaneously forecast possible lava eruptions and track the wellfield production and injection fluid impacts to optimize geothermal reservoir management. Multiple physical and chemical parameters can be examined for volcanic-seismic-exploitation correlations that may increase thermal energy recovery and reduce the attendent risks.

## A.9 GEOTHERMAL WELLS AND WELLFIELD CONCEPTS AND OPTIONS

The important tasks in future geothermal drilling in the KERZ will be to increase well productivity and reduce well costs. An early evaluation of directed, angled completion intervals seems appropriate, given the common feature of near vertical and planar fractures, partings and dikes parallel to the rift axis, in the expected production intervals. The four penetrations of the fluid yielding reservoir to date were in vertical wellbores, which is less than an optimal orientation to intercept near vertical openings. If an upper reservoir yield of 100 percent steam production could be achieved by more precise completions, possibly in the 4000 to 6000 foot depth interval as suggested in the KS wells, a productivity increase and associated cost reduction might significantly assist initial wellfield development. This finding would next invite consideration of "big hole" production wells.

In the context of improving well productivity and accurately measuring the results, it is important to note that initial well flow testing of KERZ geothermal wells is not a simple and low cost task (D'Olier and Iovenitti, 1984). The presence of cool groundwater aquifers to possible depths of about 2000 feet calls for gradual preparations. An initial static warmup (first geothermal fluids rising within the completion fluid column of the shut-in well) followed by accelerated heating and deliberate bleeding will elevate the wellbore to a more uniform thermal state to accommodate the initial high mass - high temperature flow upon opening. The capacity to go promptly to fully opened, vertically vented flow to atmosphere must be present because of an extremely erosive initial discharge of a sharp grit of rock and minerals from the producing formation. A continuous, full open flow, with its 120 decibel noise penalty, appears to be the most efficient, fast and safe procedure to obtain this critical well cleanup before shunting the flow into measurement runs and muffled venting.

As waste fluid injection is thoroughly evaluated and is considered for high utilization in the KERZ, the function and reliability of injection wells will become as critical to system operations as production wells are. Expecting a design and quality comparable to production wells, injectors must be further protected with a hang down casing string (replaceable) as the injectate conduit to the perforated linered interval at depth. Actually, marginal production wells may be placed on back up injection service with the addition of a protective hang down string. It appears that accurate and detailed knowledge of geothermal reservoir performance and optimal utilization of every well will be essential in the KERZ.

## A.10 MATURITY OF TECHNOLOGY

The improvement of geothermal well design and material selection will be important considerations for economic development of KERZ reservoirs. The conventional design and K-55 grade of casing and liner used in the HGP-A well seems to be endorsed by more than seven years of continuous production. However, the down hole conditions of this wellbore are poorly known. The costs of the offset wells, at industry market rates in the early 1980's, commonly exceeded $2,000,000 per well for drilling and completion. Substantial improvements in logistics and management of future development drilling should be important cost reduction factors. Upgrades in tubular materials, couplings, and possible cementing in tension procedures may provide gains on a benefit-to-cost basis. Modern rotary drilling, cementing and drilling fluid practices are mature practices that should serve efficiently in KERZ geothermal wellfields. ANSI 900 series wellhead equipment is indicated for standard utilization on KERZ production wells.

The production of two-phase fluid production and 100 percent steam production are mature geothermal industry technologies. High volume liquid injection into a producing geothermal reservoir is a developing technology in the industry. Injection into KERZ reservoirs may prove difficult to integrate with the production objectives; an alternate injection disposal target may be deep seawater zones immediately south of the expected geothermal reservoirs.

The substantial daily fluctuation of the Oahu power requirements indicates that PROPOSERS should consider a load-following, daily cycling of KERZ geothermal wellfield production as one option among other possible responses. Daily cycling in the form of a shared reduction of steam supply, from a wellfield sector producing commonly to one generating plant, is not known to be a sustained practice anywhere in the geothermal industry at this time. The required reduction alternatively might be achieved by a nightly shut-in of a much smaller number of wells. The impacts of a common nightly reduction, or of a selected (or rotated) full shut-in, will relate to the magnitude of pressure and temperature increases imposed in each wellbore, wellhead and flow control valve and to the endurance or quality of well design, materials and equipment. All of these factors will be site specific to the geothermal reservoirs, producing wells and economics to be encountered in the KERZ.

## A.11 OPERATIONS AND MAINTENANCE

Replacement (makeup) well drilling, redrilling for extended or improved production or injection service, and remedial cleanouts may become significant requirements in KERZ geothermal fields. No other extraordinary requirements are indicated.

## A.12 REFERENCES FOR APPENDIX A

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TABLE A-1
ISLAND OF HAWAII VOLCANIC CENTERS

| Volcano | Oldest Lava or Flow Dates* (years age ) | Eruptions | Seismicity |
|---|---|---|---|
| Kohala | 700,000 K-Ar max | Last event 60,000 years ago | Minimal |
| Mauna Kea | 375,000 K-Ar max | Last event 4500 years ago | Minimal |
| Hualalai | 106,000 K-Ar max | 1800 A.D. | Minimal |
| Mauna Loa | 400,000 K-Ar max 38,000 C14 max | 37 events 1832-1984 | Occasional |
| Kileaua | 23,000 C14 max | 64 events 1790-1989 continuous since 1983 | High |
| Loihi | Fresh tholeiite flows at summit, Age? | Per swarm? | Shallow swarms 1971-75-84 |

*K-Ar Potassium-Argon dating
C14 Radiocarbon dating

TABLE A-2
KERZ DEEP GEOTHERMAL WELLS

| Well | Total Depth (feet) | BHT* (°F) | Comments |
|---|---|---|---|
| Ashida 1 | 8300 | 619 | No permeability or fluids; suspended |
| HGP-A | 6450 | 676 | Producing ±110,000 lbs/hr TMF since Dec 81; about 43 percent steam and 57 percent brine |
| Kapoho State 1 | 7290 | 642 | Short test; 72,000 lbs/hr steam;** suspended |
| Kapoho State 2 | 8005 | 648 | Short test; 33,000 lbs/hr steam;** suspended |
| Kapoho State 1A | 6562 | 572 | Tested; data proprietary; shut in |
| Lanipuna 1 | 8389 | 685+ | Low perm., trace of fluids; abandoned |
| Lanipuna 1 redrill | 6299 | 300 | 379°F maximum; no fluids; abandoned |
| Lanipuna 6 | 4956 | 250+ | Major L.C. zone below 4285' suspended |

*Bottom hole temperature
**see Iovenitti and D'Olier, 1985

Table modified from Thomas, 1987

Well locations are shown on Figure A-6

TABLE A-3 GEOTHERMAL FLUID CHEMICAL COMPOSITION COMPOSITE DATA[a]

| Element | Brine[b] (ppm(w)) | Steam Condensate[b] (ppm(w)) |
|---|---|---|
| Na | 600 - 10,000 | 0.17 |
| K | 123 - 2,700 | 0.10 |
| Ca | 40 - 920 | 0.10 |
| Mg | 1 - 2 | <0.1 |
| Fe | <1 - 8.4 | 0.05 |
| Mn | <1 - 8.5 | -- |
| B | 4 - 11 | <0.05 |
| Br | 40 - 80 | -- |
| I | <20 | -- |
| F | 0.2 - 0.9 | -- |
| Li | 1 - 9 | <0.01 |
| Cl | 925 - 21,000 | <2 |
| $NH_3$ | <0.01 - 0.1 | 0.12 |
| $SO_4$ (c) | 9.2 - 24 | 13 |
| Hg | <0.001 - <0.05 | -- |
| As | 0.09 - 0.4 | <0.01 |
| S= (d) | 5 - 100 | -- |
| Total Alkalinity | <10 | <10 |
| $HCO_3$ | 0 - 18 | 0 |
| $CO_3$ | 0 | 0 |
| $SiO_3$ | 420 - 1,500 | 0.7 |
| TSS | 70 | -- |
| TDS (e) | 2,500 - 35,000 | 15 |
| pH | <5 - 5.5 | 3.5 |
| Conductivity (mho/cm) | 3,100 - 67,000 | 120 |
| Density | 1.03 | -- |

[a] Composite data from three wells on the PGV site (KS-1, KS-1A, and KS-2) and the HGP-A well.

[b] Wellhead pressure (WHP) = 155 psig; Wellhead Temperature (WHT) = 368°F.

[c] Concentration high due to oxidation of S= to $SO_4$.

[d] Concentration low due to oxidation of S= to $SO_4$.

[e] TDS = Total Dissolved Solids.

(from Department of Business and Economic Development, 1989)

Table A-4 NONCONDENSABLE GAS COMPOSITION COMPOSITE DATA[a]

| Gas | Observed Steam Content ppm(w) | Plant Design Composition ppm(w) |
|---|---|---|
| $CO_2$ | 250 - 1,042 | 956 |
| $H_2S$ | 800 - 1,300 | 1950 |
| $NH_3$ | (c) | - |
| Ar | 6 - 13 | - |
| $N_2$ | 10 - 700 | 582 |
| $CH_4$ | (d) | - |
| He | <0.009 | - |
| $H_2$ | 11 - 140 | 12 |
| Total NCG | 1,500 - 2,200 | 3500 |

[a] Composite data from three wells on the PGV site (KS-1, KS-1A, and KS-2) and the HGP-A well.
[b] WHP = 155 psig; WHT = 368°F.
[c] Below Detection Limit (<1.5 ppm $NH_3$ in KS-1A).
[d] Below Detection Limit (<0.2 ppm $CH_4$ in KS-1A).

(from Department of Business and Economic Development, 1989)

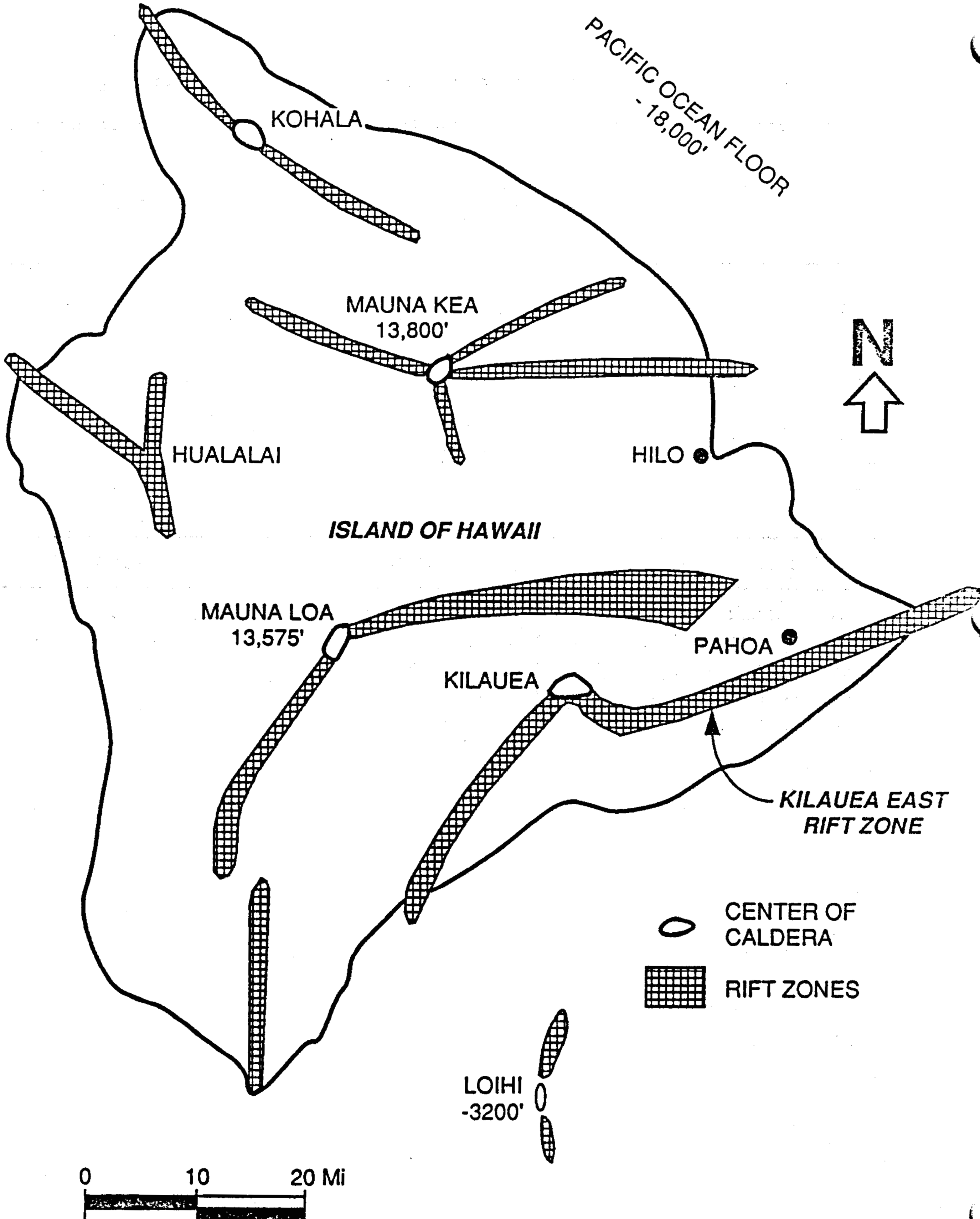


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**Figure A - 1**
**VOLCANIC CENTERS AND RIFT ZONES**

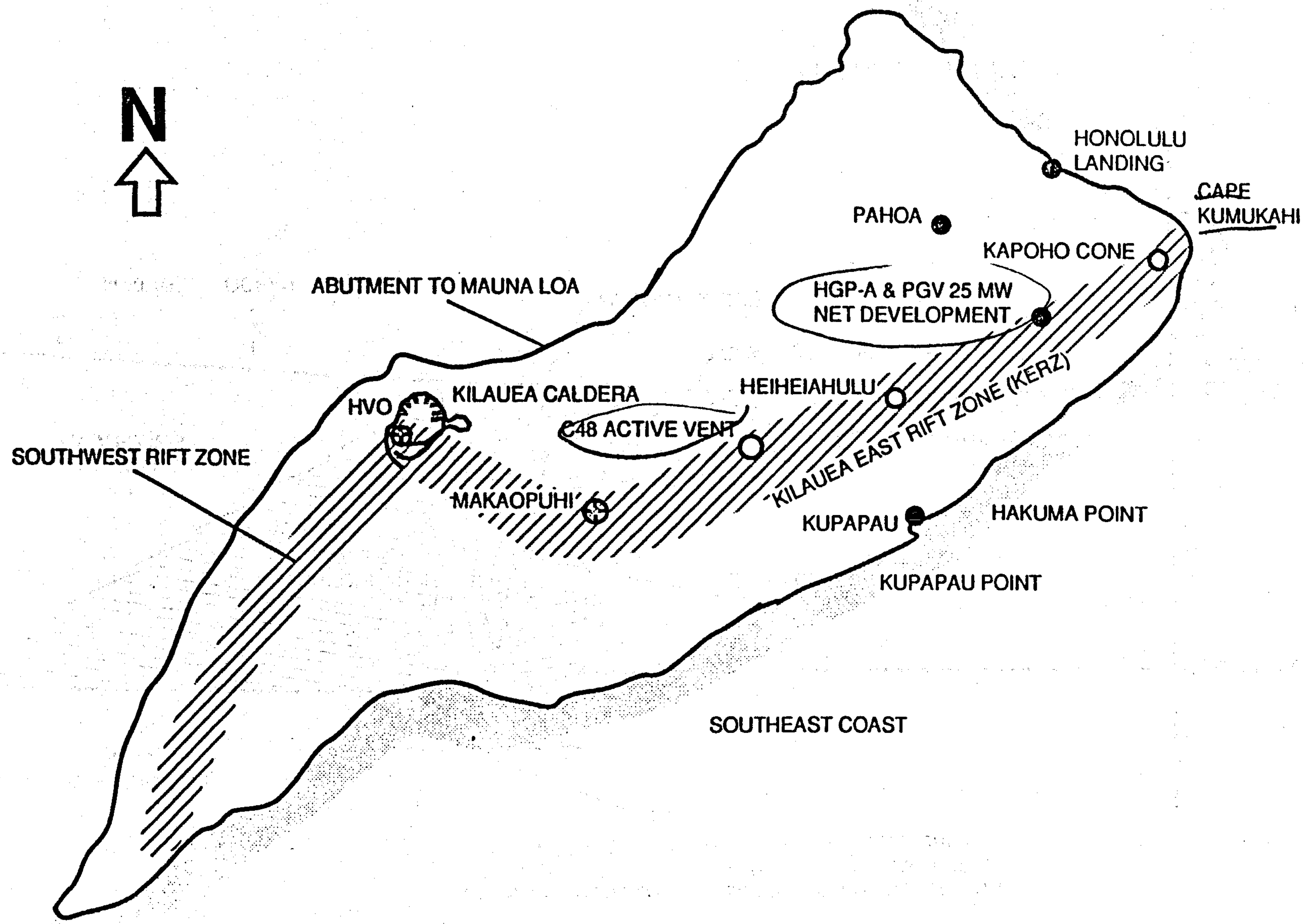



Figure A - 2
KILAUEA VOLCANO AND RIFT ZONES

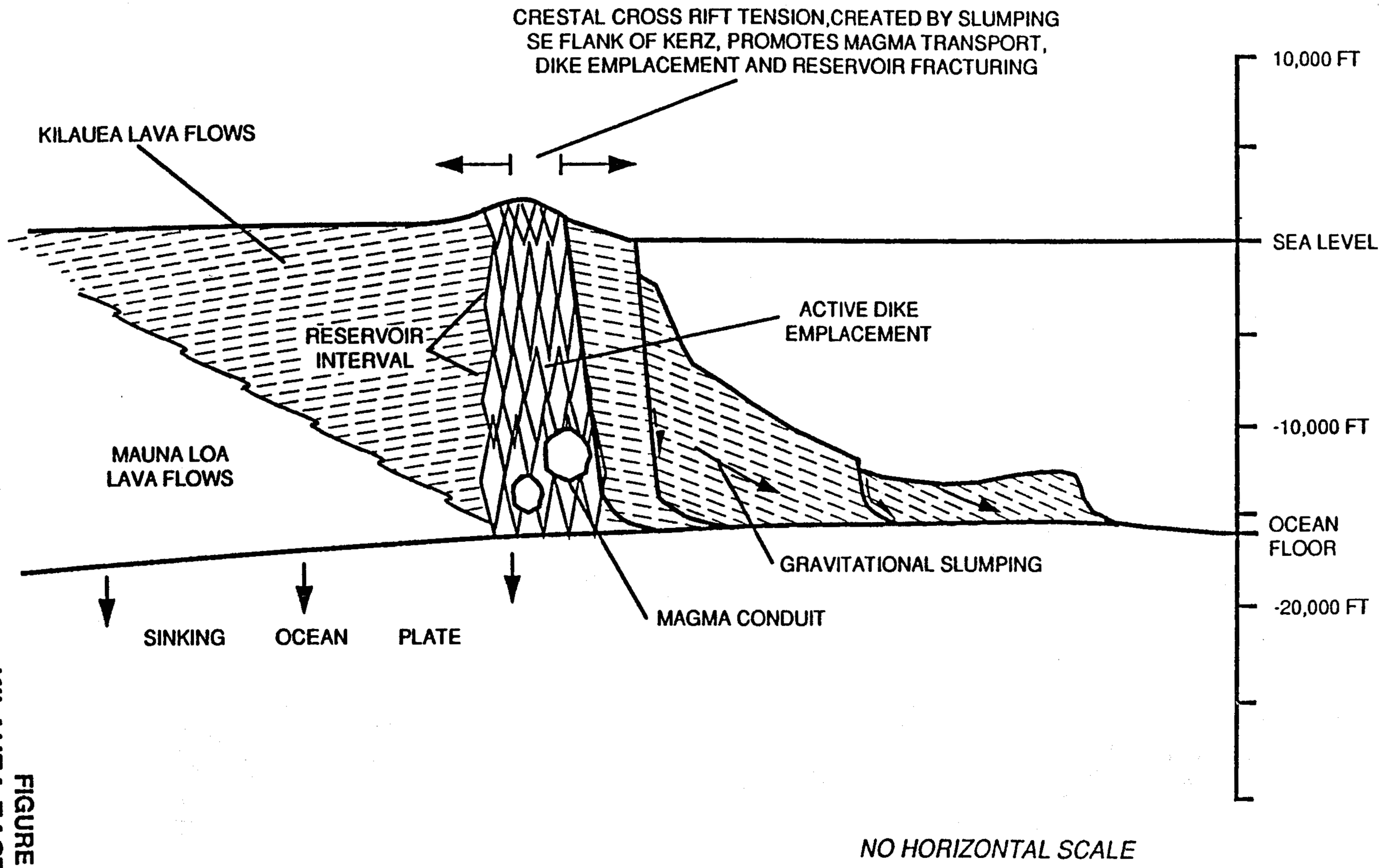



FIGURE A - 3
KILAUEA EAST RIFT ZONE
CROSS-SECTION

69007

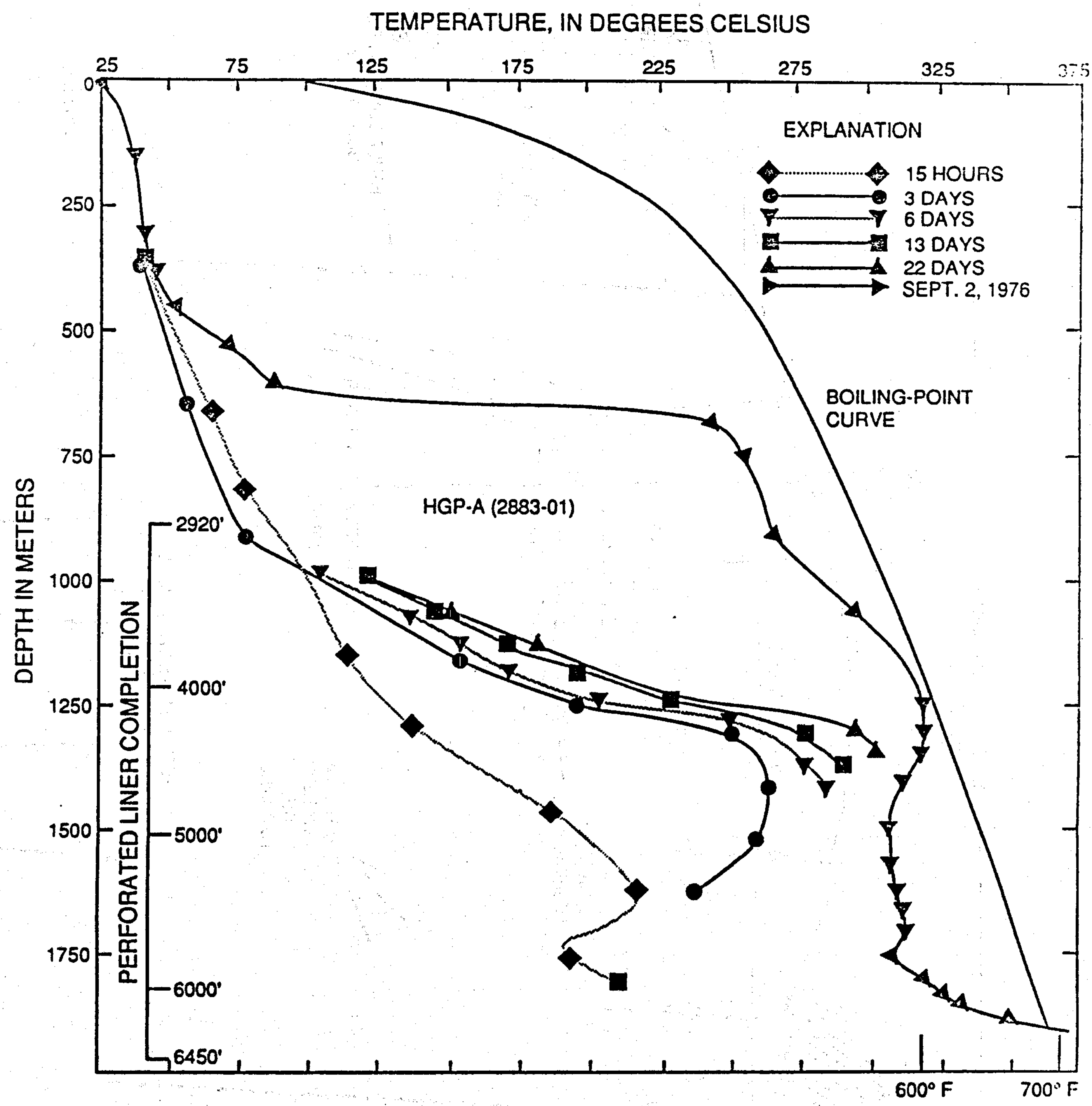



**Figure A - 4**
**HGP-A WELL TEMPERATURES**

M0489013

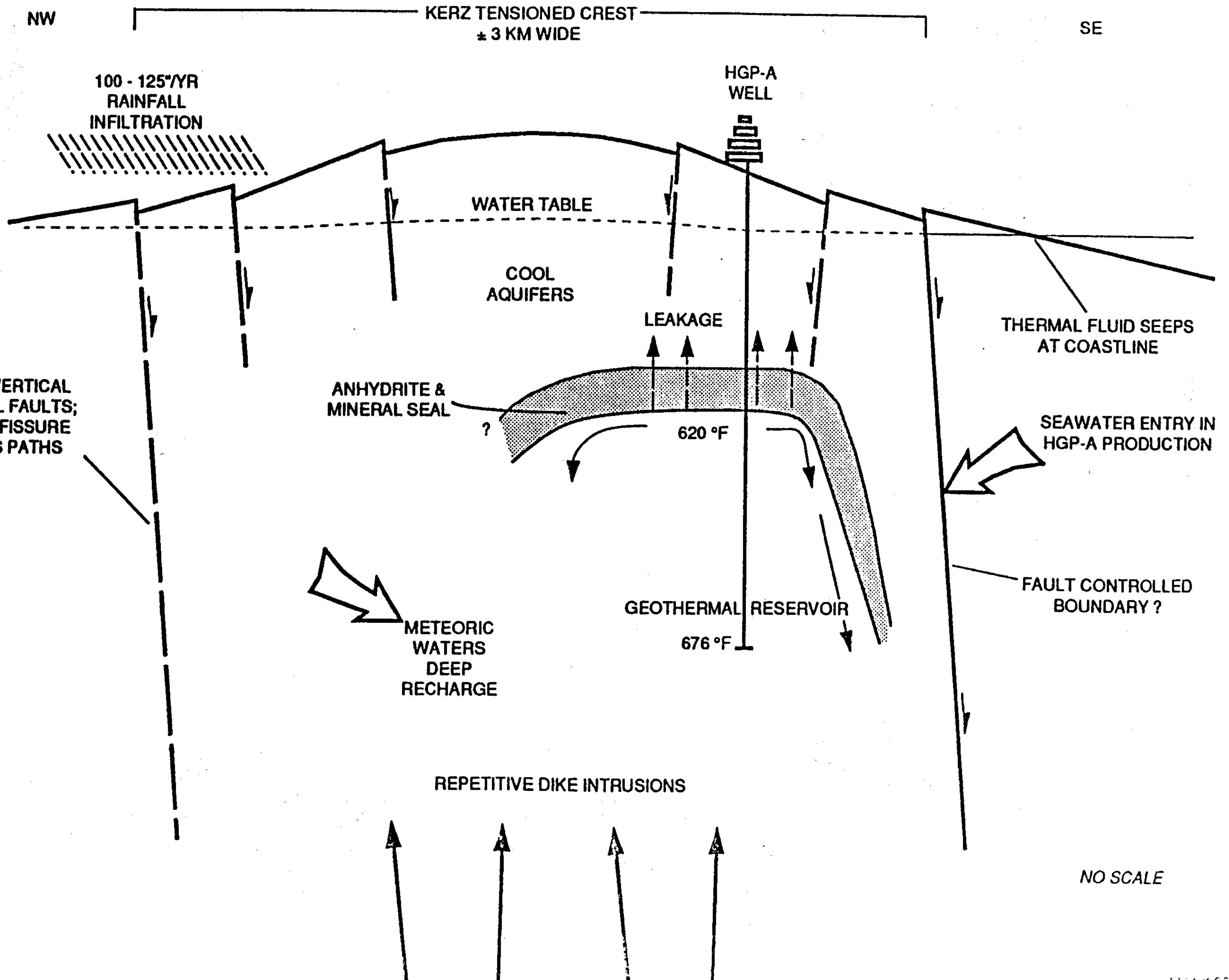
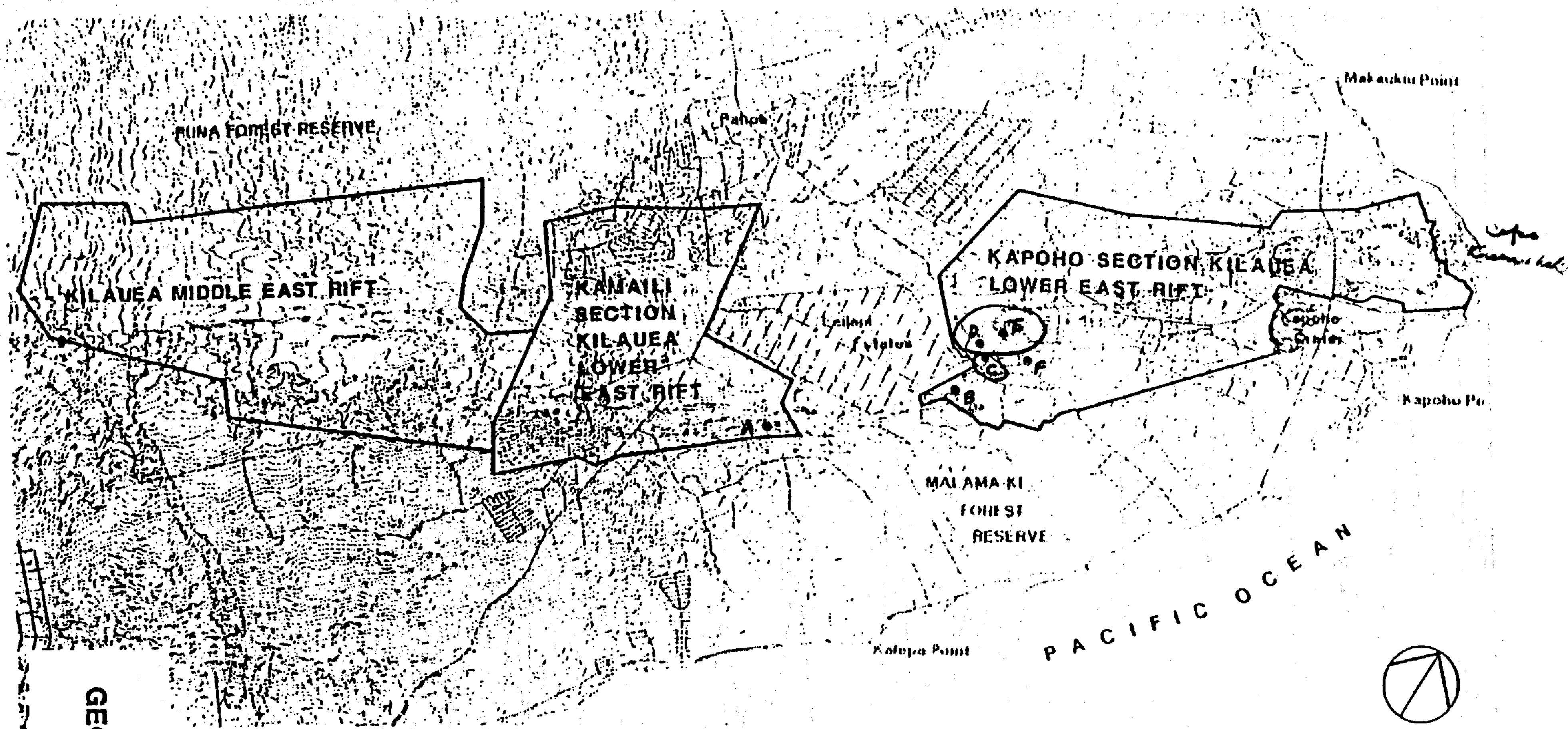



Figure A - 5
HYPOTHETICAL GEOTHERMAL
RESERVOIR IN KERZ




1 0 1 2

Scale in Miles

DEEP GEOTHERMAL WELLS

| | |
|---|---|
| A Ashida 1 | D Kapoho State 1 and 1A |
| B Lanipuna 1 and redrill | E Kapoho State 2 ORMAT |
| C HGP-A | F Lanipuna 6 |

**FIGURE A-6**
**GEOTHERMAL RESOURCE SUBZONES**

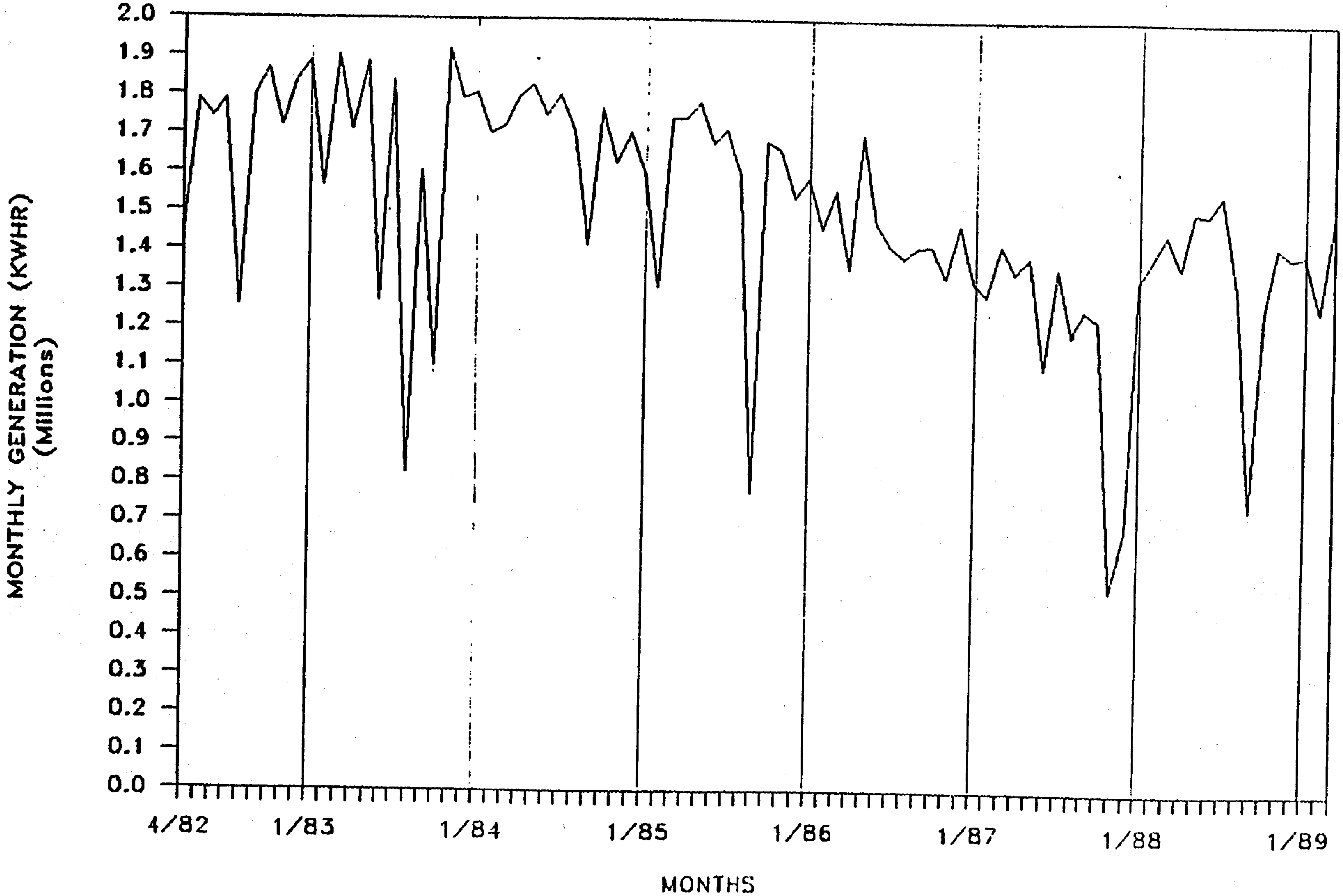
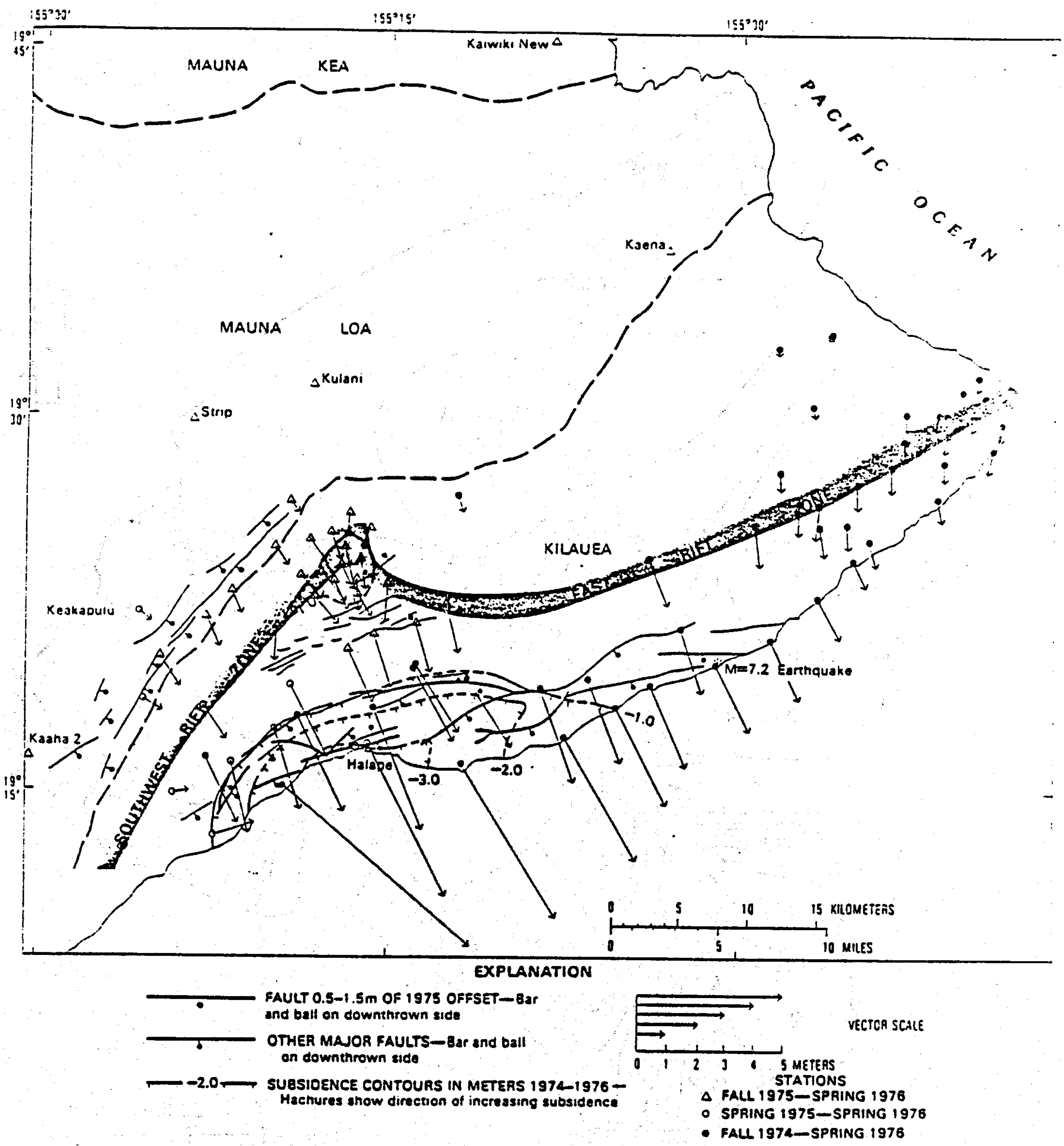



FIGURE A - 7
HGP-A OPERATIONAL
SUMMARY




**(From USGS Professional Paper 1276: Lipman, et al, 1985)**

**Figure A - 8**
**DISPLACEMENTS ASSOCIATED WITH NOVEMBER 1975 EARTHQUAKE**

M0489040

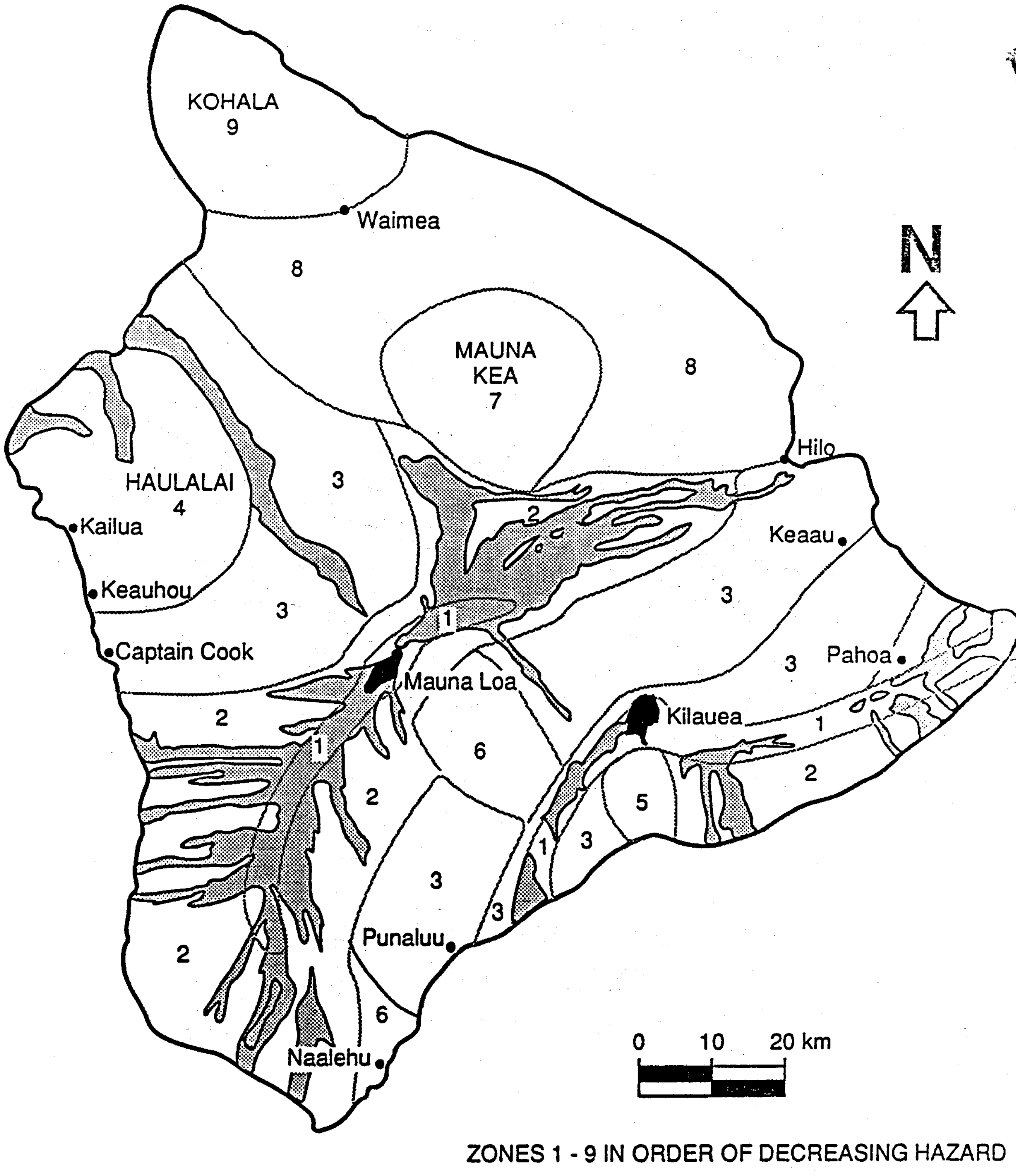



**Figure A - 9**
**LAVA FLOW HAZARD ZONES**

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